Carbon TerraVault II

Class VI Permit Application

Narrative Report

4-25-2022

Submitted to:

U.S. Environmental Protection Agency Region 9

San Francisco, CA

Prepared by:

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1.0 Project Background and Contact Information

Carbon TerraVault Holdings LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate two CO_2 geologic sequestration wells at CTV II, [redacted] located in San Joaquin County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81) under the Safe Drinking Water Act (SDWA). CTV is not requesting an injection depth waiver or aquifer exemption expansion.

CTV will obtain the required authorizations from applicable local and state agencies, including the associated environmental review process under the California Environmental Quality Act. Appendix A1 outlines potential local, state and federal permits and authorizations. Federal act considerations and additional consultation, which includes the Endangered Species Act, the National Historic Preservation Act and consultations with Tribes in the area of review, are presented in the Federal Acts and Consultation attachment.

CTV forecasts the potential CO_2 stored in the [redacted] The anthropogenic CO_2 will be sourced from direct air capture and other CO_2 sources in the CTV II area.

The Carbon TerraVault II (CTV II) storage site is located in the Sacramento Valley, [redacted] miles southeast of [redacted] (**Figure 2.1-1**) within the [redacted] The project will consist of two existing injectors, surface facilities, and monitoring wells. This supporting documentation applies to the two injection wells.

CTV will actively communicate project details and submitted regulatory documents to County and State agencies:

1. Geologic Energy Management Division (CalGEM)
   District Deputy
   Mark Ghann-Amoah (661)-322-4031

2. CA Assembly District 13
   Assemblyman Carlos Villapudua
   31 East Channel Street – Suite 306
   Stockton, CA 95202
   (209) 948-7479

3. San Joaquin County
District 3 Supervisor –Tom Patti
(209) 468-3113
tpatti@sjgov.org

4. San Joaquin County Community Development
Director – David Kwong
1810 East Hazelton Avenue
Stockton, CA 95205
(209) 468-3121

5. San Joaquin Council of Governments
Executive Director – Diane Nguyen
555 East Weber Avenue
Stockton, CA 95202
(209) 235-0600

6. Region 9 Environmental Protection Agency
75 Hawthorne Street
San Francisco, CA 94105
(415) 947-8000

2.0 Site Characterization

2.1 Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

2.1.1 Field History

The CTV II storage site overlaps [redacted] Located in a region of prolific gas production, approximately [redacted] miles [redacted] in California (**Figure 2.1-1**). [redacted].

[redacted]

Figure 2.1-1. Location map of the [redacted] with the proposed injection AoR in relation to the Sacramento Basin.

2.1.2 Geology Overview

The [redacted] lies within the Sacramento Basin in northern California (**Figure 2.1-2**). The Sacramento Basin is the northern, asymmetric sub-basin of the larger, Great Valley Forearc. This portion of the basin, that contains a steep western flank and a broad, shallow eastern flank, spans approximately 240 miles in length and 60 miles wide (Magoon 1995).

[redacted]

Figure 2.1-2. Location map of California modified from (Beyer, 1988) & (Sullivan, 2012). The Sacramento Basin regional study area is outlined by a dashed black line. B – Bakersfield; F – Fresno; R – Redding.

2.1.2.1 Basin Structure

The Great Valley was developed during mid to late Mesozoic time. The advent of this development occurred under convergent-margin conditions via eastward, Farallon Plate subduction, of oceanic crust beneath the western edge of North America (Beyer 1988). The convergent, continental margin, that characterized central California during the Late Jurassic through Oligocene time, was later replaced by a transform-margin tectonic system. This occurred as a result of the northward migration of the Mendocino Triple Junction (from Baja California to its present location off the coast of Oregon), located along California's coast (**Figure 2.1-3**). Following this migrational event was the progressive cessation of both subduction and arc volcanism as the progradation of a transform fault system moved in as the primary tectonic environment (Graham 1984). The major current day fault, the San Andreas, intersects most of the Franciscan subduction complex, which consists of the exterior region of the extinct convergent-margin system (Graham 1984).

[redacted]

2.1-3. Migrational position of the Mendocino triple junction (Connection point of the Gorda, North American and Pacific plates) on the west and migrational position of Sierran arc volcanism in the east (Graham, 1984). Figure indicates space-time relations of major continental-margin tectonic events in California during Miocene.

2.1.2.2 Basin Stratigraphy

The structural trough that developed subsequent to these tectonic events, that became named the Great Valley, became a depocenter for eroded sediment and thereby currently contains a thick infilled sequence of sedimentary rocks. These sedimentary formations range in age from Jurassic to Holocene. The first deposits occurred as an ancient seaway and through time were built up by the erosion of the surrounding structures. The basin is constrained on the west by the Coast Range Thrust, on the north by the Klamath Mountains, on the east by the Cascade Range and Sierra Nevada and the south by the Stockton Arch Fault (**Figure 2.1-2**). The west, Coastal Range boundary was created by uplifted rocks of the Franciscan Assemblage (**Figure 2.1-3**). The Sierra Nevadas, that make up the eastern boundary, are a result of a chain of ancient volcanos.

[redacted]

Figure 2.1-4. Schematic W-E cross-section of California, highlighting the Sacramento Basin, as a continental margin during late Mesozoic. The oceanic Farallon plate was forced below the west coast of the North American continental plate.

Basin development is broken out into evolutionary stages at the end of each time-period of the arc-trench system, from Jurassic to Neogene, in **Figure 2.1-5**. As previously stated, sediment infill began as an ancient seaway and was later sourced from the erosion of the surrounding structures. Due to the southward tilt of the basin, sedimentation [redacted], creating sequestration quality sandstones. Sedimentary infill consists of Cretaceous-Paleogene fluvial, deltaic, shelf and slope sediments.

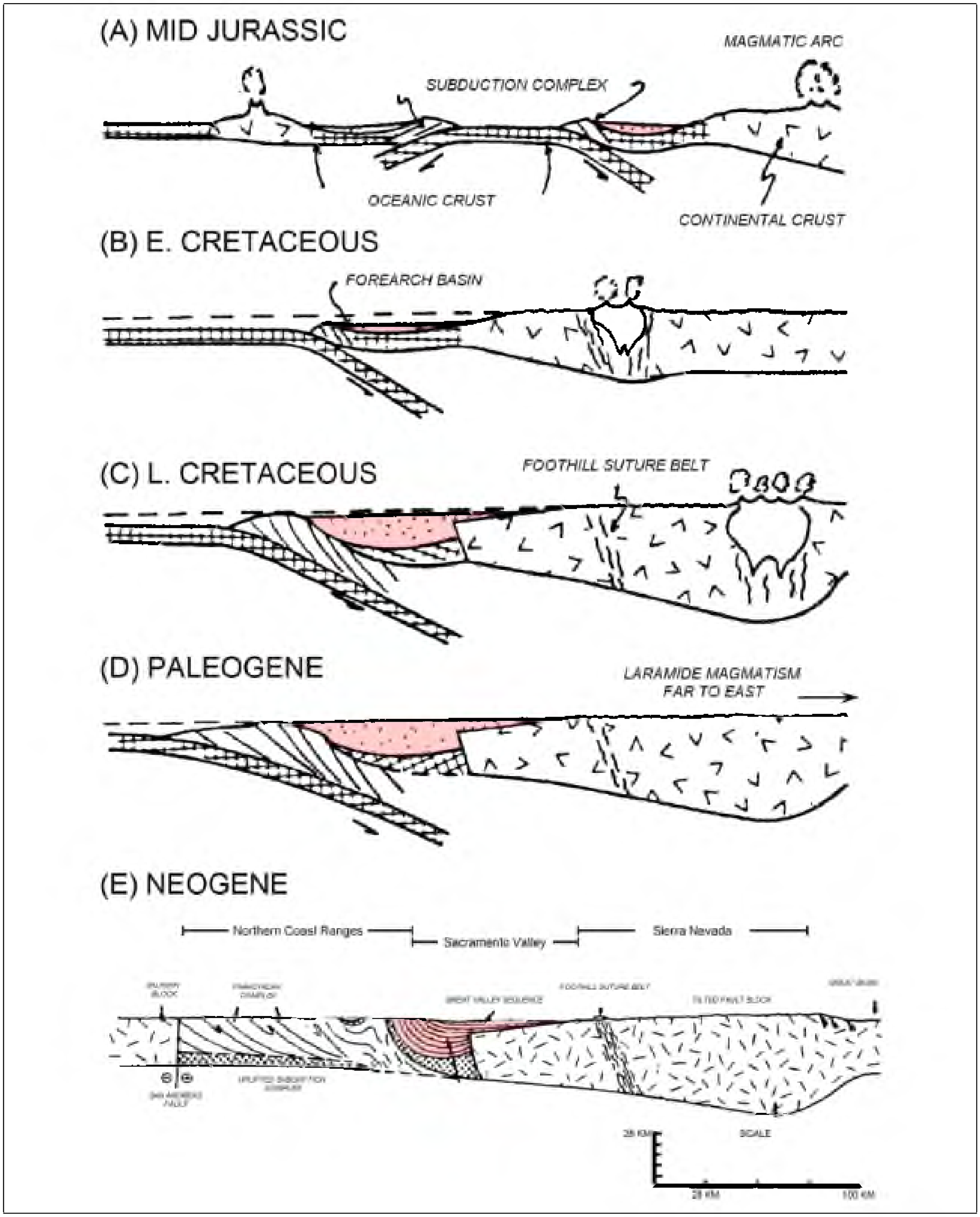

Figure 2.1-5. Evolutionary stages showing the history of the arc-trench system of California from Jurassic (A) to Neogene (E) (modified from Beyer, 1988).

[redacted]

2.1.3 Geological Sequence

[redacted]

Figure 2.1-6. Schematic northwest to southeast cross section in the Sacramento basin, intersecting the project AoR.

[redacted]

[redacted].

[redacted]

FIGURE 2.1-7. [redacted] isopach map for the greater storage project area. Wells shown as blue dots on the map penetrate [redacted] and have open-hole logs. Wells with relative permeability or capillary pressure data are shown as magenta circles.

2.2 Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

2.2.1 Data

[redacted]

[redacted]

Figure 2.2-1: Wells drilled in [redacted] with porosity data are shown in black, wells with core are shown in green and wells used for ductility calculation are shown in pink.

Well data are used in conjunction with three-dimensional (3D) and two-dimensional (2D) seismic to define the structure and stratigraphy of the injection zone and confining zone (**Figure 2.2-2**). **Figure 2.2-3** shows outlines of the seismic data used and the area of the structural framework that was built from these seismic surveys. The 3D data in this area were merged using industry standard pre-stack time migration in 2013, allowing for a seamless interpretation across them. The 2D data used for this model were tied to this 3D merge in both phase and time to create a standardized datum for mapping purposes. The following layers were mapped across the 2D and 3D data:

- A shallow marker to aid in controlling the structure of the velocity field
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

Figure 2.2-2. Type well from the southern edge of the AoR boundary showing average rock properties used in the model for confining and injection zones.

[redacted]

Figure 2.2-3: Summary map and area of seismic data used to build structural model. Both of the 3D surveys were acquired in 1998 and reprocessed in 2013. The 2D seismic were acquired between 1980 and 1985. California gas fields are shown for reference.

The top of the [redacted] was used as the base of this structural model due to the depth and imaging of Basement not being sufficient to create a reliable and accurate surface. Interpretation of these layers began with a series of well ties at well locations shown in **Figure 2.2-3**. These well ties create an accurate relationship between wells which are in depth and the seismic which is in time. The layers listed above were then mapped in time and gridded on a 550 by 550-foot cell basis. Alongside this mapping was the interpretation of any faulting in the area which is discussed further in the Faults and Fracture section of this document.

The gridded time maps and a sub-set of the highest quality well ties and associated velocity data are then used to create a three-dimensional velocity model. This model is guided between well control by the time horizons and is iterated to create an accurate and smooth function. The velocity model is used to convert both the gridded time horizons and interpreted faults into the depth domain. The result is a series of depth grids of the layers listed above which are then used in the next step of this process.

The depth horizons are the basis of a framework which uses conformance relationships to create a series of depth grids that are controlled by formation well tops picked on well logs. The grids are used as structural control between these well tops to incorporate the detailed mapping of the seismic data. These grids incorporate the thickness of zones from well control and the formation strike, dip, and any fault offset from the seismic interpretation. The framework is set up to create the following depth grids for input in to the geologic and plume growth models:

- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]
- [redacted]

- [redacted]
- [redacted]

2.2.2 Stratigraphy

[redacted]

[redacted]

Figure 2.2-4. Cross section showing stratigraphy and lateral continuity of major formations across the project area.

2.2.2.1 Delta Shale

The underlying [redacted] serves as the lower confining zone for [redacted] This formation consists of approximately [redacted] Due to the sparse well penetrations and subsequent lack of log data, this formation has been primarily mapped using seismic data as stated above.

2.2.2.2 [redacted] *(injection zone)*

Within the project area, [redacted]

This Upper Cretaceous aged formation is a deep-water sandstone with thinly interbedded sandstone and shale which overlie the [redacted] These deposits were part of a large deep-sea fan system that were sourced from granitic areas in the Sierra Nevada and fed into the system via submarine canyons and feeder channels (Williamson 1981). [redacted] Along the basin axis this sandy suprafan stacks up due to the high rate of sand supply relative to the size of the basin as well as the depositional nature of the fans at basin margins (Williamson 1981). Moving towards the upslope portion of the fan system is the [redacted] Core data is supportive of a channelized portion of the suprafan lobe (Williamson 1981). [redacted]

[redacted]

Figure 2.2-5. (a) [redacted] reservoir thickness map. (b) [redacted] reservoir structure map. AoR in red.

[redacted]

[redacted]

Figure 2.2-6. AoR and injection well location map for the project area. The injection wells are 1,735 ft. apart.

2.2.2.3 [redacted] *Confining Zone*

- [redacted]

The [redacted] which provides a regional seal [redacted] Within the AoR the average gross thickness [redacted] At the [redacted] is continuous [redacted]

- [redacted]

[redacted]

-[redacted]

2.2.2.4 [redacted] The [redacted] creating a thicker shale.

2.2.2.5 [redacted]

-[redacted]

2.2.2.6 [redacted] and would act as a barrier to any CO_2, from reaching the USDW, if any migration were to occur.

2.2.2.7 [redacted]

2.2.2.8 [redacted]

Above the [redacted]

2.2.2.9 [redacted]

[redacted]

2.2.3 Map of the Area of Review

As required by 40 CFR 146.82(a)(2), **Figure 2.2-7** shows surface bodies of water, surface features, transportation infrastructure, political boundaries, and cities. Major water bodies in the area are [redacted]

This figure does not show the surface trace of known and suspected faults because there are no known surface faults in the AoR. There are also no known mines or quarries in the AoR. **Figure 2.2-8** indicates the locations of State- or EPA-approved subsurface cleanup sites. This cleanup site information was obtained from the State Water Resources Control Board's GeoTracker database, which contains records for sites that impact, or have the potential to impact, groundwater quality. Water wells within and adjacent the AoR are discussed in Section 2.7.7 of this document.

[redacted]

Figure 2.2-7. Surface Features and the AoR

[redacted]

Figure 2.2-8. State or EPA Subsurface Cleanup Sites

2.3 Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

2.3.1 Overview

[redacted]

The 3D seismic data described in the prior section were used together with well control to define the fault planes within the geologic model boundary. [redacted] along with the location of an example structural cross-section shown in **Figure 2.3-2**. [redacted]

[redacted]

Figure 2.3-1. [redacted] Yellow line highlights the cross-section shown in **Figure 2.3-2**

[redacted]

[redacted]

Figure 2.3-2. Structural cross section across the geologic model. [redacted] is shown with SP log (negative values to left) for correlation and geologic packages. Geologic surfaces developed from seismic interpretation. [redacted]

[redacted]

[redacted]

2.4 Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

2.4.1 Mineralogy

No quantitative mineralogy information exists within the AoR boundary. Mineralogy data will be acquired across all the zones of interest as part of pre-operational testing. Several wells outside the AoR have mineralogy over the respective formations of interest, and that data is presented below.

2.4.1.1 [redacted]

Core descriptions for 3 wells within the AoR mention that the [redacted] consists of "quartz, feldspar (plagioclase & K-spar), mica, ferromags, and lithics." Calcite cemented intervals of sandstone are also present within the core, generally as thin "bones" or "sandstone 'shell'" and are confirmed by log data. The exact mineralogic content of these bones is unknown. X-ray diffraction (XRD) data from the [redacted] in the [redacted] confirm this general mineralogy (see **Figure 2.4-1**). Reservoir sand from two samples in this well averages 67% quartz, 14% plagioclase and potassium feldspar, and 12% total clay (**Table 2.4-1**). The primary clay minerals are kaolinite and smectite. Calcite & dolomite make up less than 3% of the samples.

[redacted]

Figure 2.4-1. Map showing location of wells with mineralogy data relative to the AoR.

Table 2.4-1: Formation mineralogy from X-ray diffraction in [redacted] and XRD and Fourier transform infrared spectroscopy (FTIR) in the [redacted] well.

[redacted]

2.4.1.2 Upper Confining Zone [redacted]

No representative mineralogy data is available for the upper confining zone. Mineralogy data is available for the [redacted] a similar Cretaceous age shale directly above the upper confining zone, from the [redacted] (see **Figure 2.4-1**) in the form of XRD and FTIR data. Nine samples for this zone show an average of 46% total clay, with mixed layer illite/smectite being the dominant species, with kaolinite and chlorite still prevalent. They also contain 23% quartz, 29% plagioclase and potassium feldspar, 2% pyrite, and 1% calcite & dolomite (**Table 2.4-1**).

2.4.1.3 [redacted]

X-ray diffraction data is available for the [redacted] in the [redacted] but most of the samples were taken within sandy intervals. Two data points [redacted] can be classified as shale based on their total clay weight percent. These samples average 46% total clay, with smectite and kaolinite being the major clay species. They also contain 40% quartz, 10% plagioclase and potassium feldspar, and 1% calcite & dolomite.

2.4.2 Porosity and Permeability

2.4.2.1 [redacted]

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, compressional sonic, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined one of two ways: from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using 55.5 µsec/ft matrix slowness and the Raymer-Hunt equation.

Volume of clay is determined by spontaneous potential and is calibrated to core data.

Log-derived permeability is determined by applying a core-based transform that utilizes capillary pressure porosity and permeability along with clay values from XRD or FTIR. Core data from two wells with 13 data points was used to develop a permeability transform. An example of the transform from core data is illustrated in **Figure 2.4-2** below.

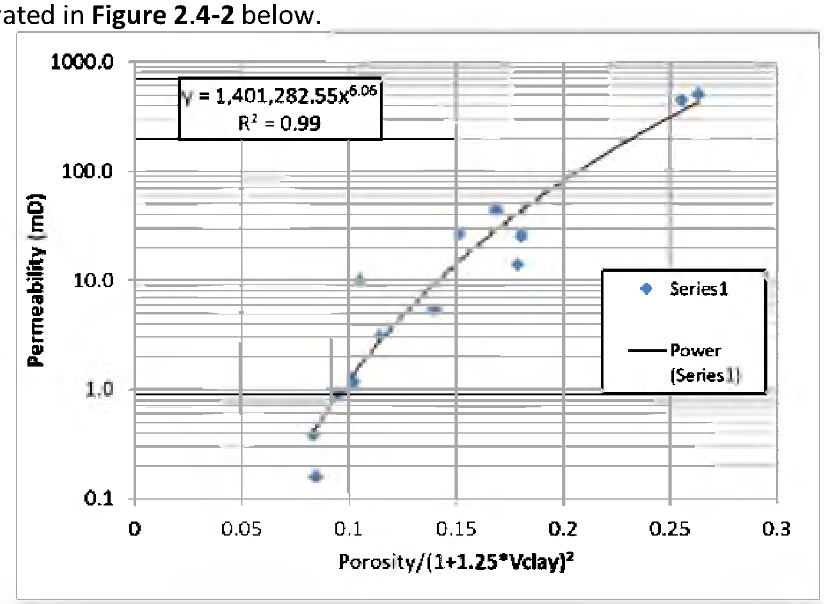

Figure 2.4-2. Permeability transform for Sacramento basin zones.

In the example well below, [redacted] for the [redacted] the porosity ranges from 1% - 26% with a mean of 17% (**Figure 2.4-3**). The permeability ranges from 0.0004 mD - 290 mD with a log mean of 5.6 mD (**Figure 2.4-4**).

[redacted]

Figure 2.4-3. Porosity histogram for well [redacted] In the histogram, blue represents the [redacted] red the [redacted] and brown the [redacted] For the two shale intervals, only data with VCL>0.25 is shown, and for the [redacted] only data with VCL<=0.25 is shown.

[redacted]

Figure 2.4-4. Permeability histogram for well [redacted] In the histogram, blue represents the [redacted] red the [redacted] and brown the [redacted] For the two shale intervals, only data with VCL>0.25 is shown, and [redacted] data with VCL<=0.25 is shown.

A log plot for the [redacted] is included in **Figure 2.4-5**. Core porosity and permeability are shown in comparison to log calculated porosity and permeability.

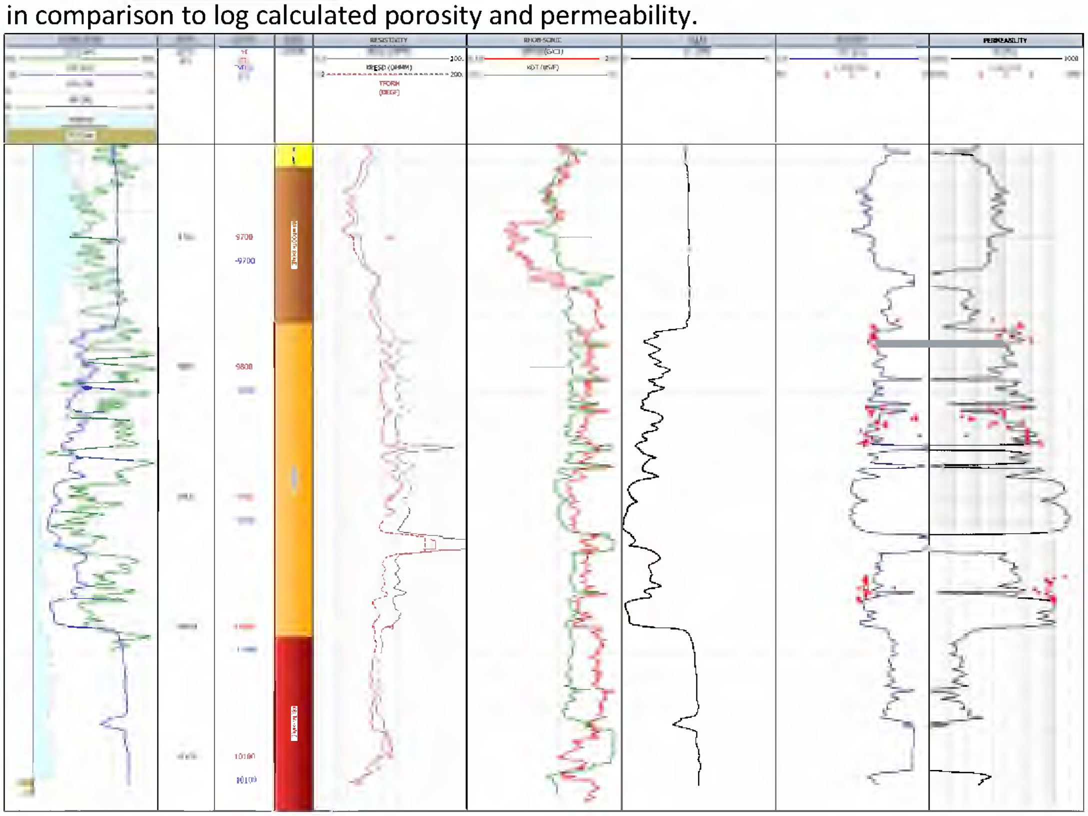

Figure 2.4-5. Log plot for well [redacted] showing the log curves used as inputs into calculations of clay volume, porosity and permeability, and their outputs. Core data for porosity and permeability is shown for comparison to the log model. Track 1: Correlation and caliper logs. Track 2: Measured depth. Track 3: Vertical depth and vertical subsea depth. Track 4: Zones. Track 5: Resistivity. Track 6: Compressional sonic and density logs. Track 7: Volume of clay. Track 8: Porosity calculated from log curves and core porosity. Track 9: Permeability calculated using transform and core permeability.

The average porosity for the [redacted] is 18.9%, based on 19 wells with porosity logs and 8518 individual logging data points. See **Figure 2.4-6** for location of wells used for porosity and permeability averaging.

The geometric average permeability for the [redacted] is 13 mD, based on 19 wells with porosity logs and 7993 individual logging data points.

[redacted]

Figure 2.4-6. Map of wells with porosity and permeability data.

2.4.2.2 Upper Confining Zone [redacted]

The average porosity of the upper confining zone is 23.0%, based on 16 wells with porosity logs and 50563 individual logging data points.

The geometric average permeability of the upper confining zone is 0.59 mD, based on 16 wells with porosity logs and 49,662 individual logging data points.

2.4.2.3 [redacted]

The average porosity of the lower confining zone [redacted] is 14.7%, based on 13 wells with porosity logs and 2983 individual logging data points.

The geometric average permeability of the lower confining zone [redacted] is 0.04 mD, based on 13 wells with porosity logs and 2906 individual logging data points.

2.4.3 Injection and Confining Zone Capillary Pressure

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

No capillary pressure data was available for the upper confining zone. This data will be acquired as part of pre-operational testing.

For the injection zone, Capillary pressure data obtained from well [redacted] in the [redacted] was used. **Figure 2.4-7** shows the Capillary pressure curve for the Injection zone that was used for the Computational modeling. Further details, and location of the well are discussed in Attachment B.

[redacted]

Figure 2.4-7: Injection zone Capillary pressure curve used in Computational modeling. Obtained from Core sample from [redacted].

2.4.4 Depth and Thickness

Depths and thickness of the [redacted] reservoir and [redacted] confining zone (**Table 2.4-2**) are determined by structural and isopach maps (**Figure 2.4-8**) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

1. [redacted] structural variability is due to the slight anticlinal structure.

2. [redacted] thickness variability due to deposition of the [redacted] In the AoR, the shale minimum thickness corresponds to a high in [redacted] sand thickness.

3. [redacted] thickness variability is from pinch-out of the reservoir [redacted]

Table 2.4-2: [redacted] and [redacted] gross thickness and depth within the AoR.

Zone	Property	Low	High	Mean
Upper Confining Zone [redacted]	Thickness (feet)	2,158	2,322	2,243
	Depth (feet TVD)	7,208	7,788	7,456
Reservoir [redacted]	Thickness (feet)	120	365	256
	Depth (feet TVD)	9,482	9,994	9,727

[redacted]

Figure 2.4-8. Gross thickness and depth maps within the AoR for the [redacted]

2.4.5 Structure Maps

Structure maps are provided in order to indicate a depth to reservoir adequate for supercritical-state injection.

2.4.6 Isopach Maps

Spontaneous potential (SP) logs from surrounding gas wells were used to identify sandstones. Negative millivolt deflections on these logs, relative to a baseline response in the enclosing shales, define the sandstones. These logs were baseline shifted to 0mV. Due to the log vintage variability, there is an effect on quality which creates a degree of subjectivity within the gross sand, however this will not have a material impact on the maps.

Variability in the thickness and depth of either the [redacted] or the [redacted] sandstone will not impact confinement. CTV will utilize thickness and depth shown when determining operating parameters and assessing project geomechanics.

2.5 Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

2.5.1 Caprock Ductility

Ductility and the unconfined compressive strength (UCS) of shale are two properties used to describe geomechanical behavior. Ductility refers to how much a rock can be distorted before it fractures, while the UCS is a reference to the resistance of a rock to distortion or fracture. Ductility generally decreases as compressive strength increases.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock (UCS_{NC}).

$$\log UCS = -6.36 + 2.45 \log(0.86V_p - 1172) \quad (1)$$

$$\sigma' = OB_{pres} - P_p \quad (2)$$

$$UCS_{NC} = 0.5\sigma' \quad (3)$$

$$BRI = \frac{UCS}{UCS_{NC}} \quad (4)$$

Units for the UCS equation are *UCS* in MPa and V_p (compressional velocity) in m/s. OB_{pres} is overburden pressure, P_p is pore pressure, σ' is effective overburden stress, and *BRI* is brittleness index.

If the value of BRI is less than 2, empirical observation shows that the risk of embrittlement is lessened, and the confining zone is sufficiently ductile to accommodate large amounts of strain without undergoing brittle failure. However, if BRI is greater than 2, the "risk of development of an open fracture network cutting the whole seal depends on more factors than local seal strength and therefore the BRI criterion is likely to be conservative, so that a seal classified as brittle may still retain hydrocarbons" (Ingram & Urai, 1999).

2.5.1.1 Upper Confining Zone [redacted]

Within the AoR, four wells had compressional sonic and bulk density data over the upper confining zone to calculate ductility, comprising 9633 individual logging data points (see pink squares in **Figure 2.4-1**). 16 wells had compressional sonic data over the upper confining zone to calculate UCS, comprising 59014 individual logging data points (see black circles in **Figure 2.4-1**). The average ductility of the confining zone based on the mean value is 2.0. Additionally, 65% of the shale within the confining layer has a ductility less than 2.The average rock strength of the confining zone, as determined by the log derived UCS equation above, is 4,593 psi.

An example calculation for the well [redacted] is shown below (**Figure 2.5-1**). UCS_CCS_VP is the UCS based on the compressional velocity, UCS_NC is the UCS for a normally consolidated rock, and BRI is the calculated brittleness using this method. Brittleness less than two (representing ductile rock) is shaded red.

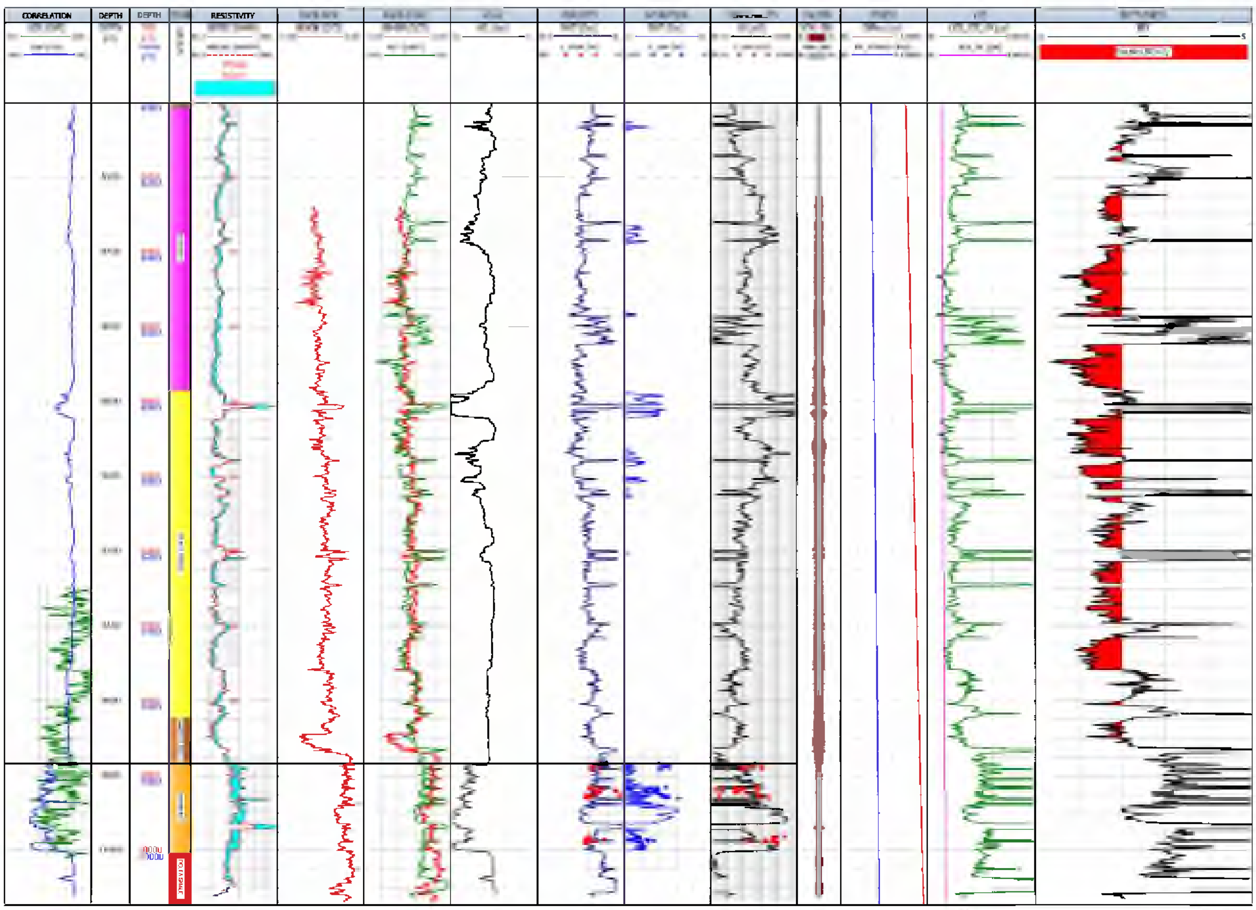

Figure 2.5-1: Unconfined compressive strength and ductility calculations for well [redacted] The upper confining zone ductility is less than two. Track 1: Correlation logs. Track 2: Measured depth. Track 3: Vertical depth and vertical subsea depth. Track 4: Zones. Track 5: Resistivity. Track 6: Density log. Track 7: Density and compressional sonic logs. Track 8: Volume of clay. Track 9: Porosity calculated from sonic and density. Track 10: Water saturation. Track 11: Permeability. Track 12: Caliper. Track 13: Overburden pressure and hydrostatic pore pressure. Track 14: UCS and UCS_NC. Track 15: Brittleness.

Within the upper confining zone, the brittleness calculation drops to a value less than two. As a result of the upper confining zone ductility, there are no fractures that will act as conduits for fluid migration from the [redacted] This conclusion is supported by the following:

1. Prior to discovery, the upper confining zone provided a seal to the underlying gas reservoir of the [redacted] for millions of years.

2.5.2 Stress Field

The stress of a rock can be expressed as three principal stresses. Formation fracturing will occur when the pore pressure exceeds the least of the stresses. in this circumstance, fractures will propagate in the direction perpendicular to the least principal stress (**Figure 2.5-2**).

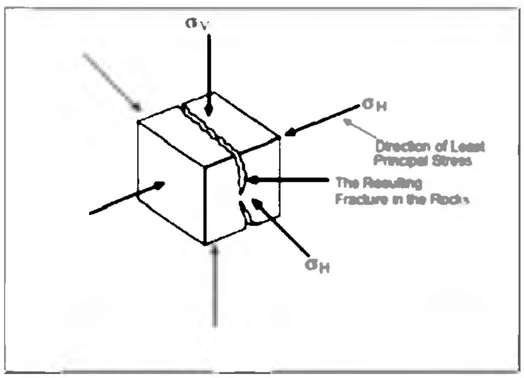

Figure 2.5-2: Stress diagram showing the three principal stresses and the fracturing that will occur perpendicular to the minimum principal stress.

Stress orientations in the [redacted] have been studied using both earthquake focal mechanisms and borehole breakouts (Snee and Zoback, 2020, Mount and Suppe, 1992). The azimuth of maximum principal horizontal stress (S_{Hmax}) was estimated at N40ºE ± 10º by Mount and Suppe, 1992. Data from the World Stress Map 2016 release (Heidbach et al., 2016) shows an average S_{Hmax} azimuth of N37.4ºE once several far field earthquakes with radically different S_{Hmax} orientations are removed (**Figure 2.5-3**), which is consistent with Mount and Suppe, 1992. The earthquakes in the area indicate a strike-slip/reverse faulting regime.

[redacted]

Figure 2.5-3: World Stress Map output showing S_{Hmax} azimuth indicators and earthquake faulting styles in the [redacted] (Heidbach et al., 2016). In red is the outline of the [redacted] The background coloring represents topography.

In the project AoR there is no site-specific [redacted] fracture pressure or fracture gradient. A [redacted] step rate test will be conducted as per the preoperational testing plan. However, several wells have formation integrity tests (FIT) for shallower formations such as the [redacted] and [redacted] A FIT performed in the [redacted] in the [redacted] recorded a minimum fracture gradient of 0.809 psi/ft. Four other wells within the field recorded minimum fracture gradients of 0.75-0.76 psi/ft based on FIT in the [redacted] and [redacted] ([redacted] FIT data for three other wells across the [redacted] averaged 0.84 psi/ft [redacted] See **Figure 2.5-4** for location of all wells. For computational modeling, a frac gradient of 0.7 psi/ft was used, which should be below the actual frac gradient assuming the [redacted] frac gradient would be similar to shallower zones.

[redacted]

Figure 2.5-4: Location of wells with FIT data.

In the project AoR there is no site-specific fracture pressure or fracture gradient for the upper confining zone. A step rate test will be conducted in the upper confining zone as per the preoperational testing plan. In the interim, CTV is making the assumption that the upper confining zone will have a similar fracture gradient as the [redacted]

The overburden stress gradient in the reservoir and confining zone is 0.94 psi/ft. No data currently exists for the pore pressure of the confining zone. This will be determined as part of the preoperational testing plan.

2.6 Seismic History [40 CFR 146.82(a)(3)(v)]

[redacted].

[redacted]

Figure 2.6-1: Fault Activity Map from the California Geologic Survey. [redacted]

The seismic interpretation provides an estimation of the time when [redacted] was last actively growing. The United States Geologic Survey (USGS) provides an earthquake catalog tool (https://earthquake.usgs.gov/earthquakes/search/) which can be used to search for recent seismicity that could be associated with faults in the area for movement. A search was made for earthquakes in the greater vicinity of the project area from 1850 to modern day with events of a magnitude greater than three. **Figure 2.6-2** shows the results of this search and **Table 2.6-1** summarizes some of the data taken from them.

[redacted]

Figure 2.6-2. Image is modified from USGS search results. Data from these events are compiled in **Table 2.6-1** in chronological order associated with events 1 through 11 on the map.

The events in **Figure 2.6-2** that could be associated with the [redacted] are events 1, 10, and 5. Event 1 is a deep event (14.6km) in 2010 which is likely related to basement movement, much deeper than the proposed injection zone or any of the sedimentary section in the basin. Event 10 is a shallower event (6.0km) which occurred in 1944, before the [redacted] was discovered in [redacted] Event 5 does sit along the trace of [redacted] but is further away from [redacted] and is therefore unrelated to [redacted] injection. The average depth of events from the USGS search results is 9.2km, substantially deeper than the proper [redacted] and the entire sedimentary section within the AoR.

Table 2.6-1: Data from USGS earthquake catalog for faults in the region of CTV II.

[redacted]

[redacted]

[redacted]

Lund-Snee and Zoback (2020) published updated maps for crustal stress estimates across North America. **Figure 2.6-3** shows a modified image from that work highlighting CTV II. This work is in agreement with previous estimates of maximum horizontal stress in the region of approximately N40°E in a strike-slip to reverse stress regime (Mount and Suppe 1992) and is consistent with World Stress map data for the area (Heidbach et al. 2016). [redacted] Attachment C of this application discusses the seismicity monitoring plan for this injection site.

[redacted]

Figure 2.6-3: Image modified from Lund Snee and Zoback (2020) showing relative stress magnitudes across California. Red star indicates CTV II project site area.

2.6.2 Seismic Hazard Mitigation

[redacted]

The following is a summary of CTVs seismic hazard mitigation for CTV II:

The project has a geologic system capable of receiving and containing the volumes of CO_2 proposed to be injected

- [redacted]

- [redacted]
- There are no faults or fractures identified in the AoR that will impact the confinement of CO_2 injectate. [redacted]

Will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events

- [redacted]
- Injection pressure will be lower than the fracture gradient of the sequestration reservoir with a safety factor (90% of the fracture gradient)
- [redacted]
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event

Will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated

- Via monitoring and surveillance practices (pressure and seismic monitoring program) CTV personnel will be notified of events that are considered an early warning sign. Early warning signs will be addressed to ensure that more significant events do not occur
- CTV will establish a central control center to ensure that personnel have access to the continuous data being acquired during operations

Minimizing potential for induced seismicity and separating any events from natural to induced

- Pressure will be monitored in each injector and sequestration monitoring well to ensure that pressure does not exceed the fracture pressure of the reservoir or confining zone
- Seismic monitoring program will be installed pre-injection for a period to monitor for any baseline seismicity that is not being resolved by current monitoring programs
- Average depth of prior seismic hazard in the region based on reviewed historical seismicity has been approximately 9.2km. Significantly deeper than the proposed injection zone
- [redacted]

2.7 Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

The California Department of Water Resources has defined 515 groundwater basins and subbasins with the state. [redacted]

[redacted]

2.7.1 Hydrologic Information

[redacted]

[redacted]

[redacted]

Figure 2.7-1 [redacted] Surface Geology, and Cross Section Index Map

2.7.2 Base of Fresh Water and Base of USDWs

The owner or operator of a proposed Class VI injection well must define the general vertical and lateral limits of all USDWs and their positions relative to the injection zone and confining zones. The intent of this information is to demonstrate the relationship between the proposed injection formation and any USDWs, and it will support an understanding of the water resources near the proposed injection wells. A USDW is defined as an aquifer or its portion which supplies any public water system; or which contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/l total dissolved solids; and which is not an exempted aquifer.

2.7.2.1 Base of Fresh Water

The base of fresh water (BFW) helps define the aquifers that are used for public water supply. Local water agencies [redacted] the geologic history of freshwater sediments from which groundwater is extracted for beneficial uses as defined and regulated under SGMA.

[redacted]

[redacted] The focus of this study was the uppermost 500 feet, where most water wells were completed. Subsequently Luhdorff & Scalmanini (2016) used logs also examined for the nature of geologic units at greater depths to better define the BFW. The top of the geophysical logs tended to be at 800 feet or greater depths. These logs generally show fine-grained geologic units with few sand beds. The depth to base of fresh water was difficult to discern in available geophysical logs because of the lack of sand beds. The elevation of the base of freshwater aquifers determined from logs were plotted on a base map (see **Figure 2.7-2**). Contour lines of one hundred feet were drawn, but are variable based on well control.

[redacted]

Figure 2.7-2 Geologic Map and Base of Fresh Water

2.7.2.2 Base of USDWs

CTV has used geophysical logs to investigate the base of the USDW. The calculation of salinity from logs used by CTV is a four-step process:

(1) converting measured density or sonic to formation porosity

The equation to convert measured density to porosity is:

$$POR = \frac{(Rhom - RHOB)}{(Rhom - Rhof)} \tag{5}$$

Parameter definitions for the equation are:

POR is formation porosity

Rhom is formation matrix density grams per cubic centimeters (g/cc); 2.65 g/cc is used for sandstones

RHOB is calibrated bulk density taken from well log measurements (g/cc)

Rhof is fluid density (g/cc); 1.00 g/cc is used for water-filled porosity

The equation to convert measured sonic slowness to porosity is:

$$POR = -1\left(\frac{\Delta tma}{2\Delta tf} - 1\right) - \sqrt{\left(\frac{\Delta tma}{2\Delta tf} - 1\right)^2 + \frac{\Delta tma}{\Delta tlog} - 1} \tag{6}$$

Parameter definitions for the equation are:

POR is formation porosity

Δtma is formation matrix slowness (µs/ft); 55.5 µs/ft is used for sandstones

Δtf is fluid slowness (µs/ft); 189 µs/ft is used for water-filled porosity

Δtlog is formation compressional slowness from well log measurements (µs/ft)

(2) calculation of apparent water resistivity using the Archie equation,

The Archie equation calculates apparent water resistivity. The equation is:

$$Rwah = \frac{POR^m R_t}{a} \tag{7}$$

Parameter definitions for the equation are:

Rwah is apparent water resistivity (ohmm)

POR is formation porosity

m is the cementation factor; 2 is the standard value

R_t is deep reading resistivity taken from well log measurements (ohmm)

a is the archie constant; 1 is the standard value

(3) correcting apparent water resistivity to a standard temperature

Apparent water resistivity is corrected from formation temperature to a surface temperature standard of 75 degrees Fahrenheit:

$$Rwahc = Rwah\frac{TEMP + 6.77}{75 + 6.77} \tag{8}$$

Parameter definitions for the equation are:

Rwahc is apparent water resistivity (ohmm), corrected to surface temperature

TEMP is down hole temperature based on temperature gradient (DegF)

(4) converting temperature corrected apparent water resistivity to salinity.

The following formula was used (Davis 1988):

$$SAL\_a\_EPA = \frac{5500}{Rwahc} \quad (9)$$

Parameter definitions for the equation are:

SAL_a_EPA is salinity from corrected Rwahc (ppm)

The base of fresh water and the USDW are shown on the geologic Cross Section A-A' (**Figure 2.2-4**) The base of fresh water and based of the lowermost USDW are at a measure depths of approximately 600 ft bgs and 2,400 ft bgs, respectively.

2.7.3 Formations with USDWs

[redacted]

2.7.3.1 Alluvium

The Alluvium (Q) includes sediments deposited in the channels of active streams as well as overbank deposits and terraces of those streams. They consist of unconsolidated silt, sand, and gravel. Sand and gravel zones in the younger alluvium are highly permeable and yield significant quantities of water to wells. [redacted]

2.7.3.2 Flood Basin and Intertidal Deposits

[redacted] These sediments consist of peaty mud, clay, silt, sand and organic materials. Stream-channel deposits of coarse sand and gravel are also included in this unit. The flood basin deposits have low permeability and generally yield low quantities of water to wells due to their fine-grained nature. Flood basin deposits generally contain poor quality groundwater with occasional zones of fresh water. The maximum thickness of the unit is about 1,400 feet (DWR 2006).

2.7.3.3 Alluvial Fan Deposits

Along the southern margin of the Subbasin, in the Non-Delta uplands areas of the Subbasin are fan deposits (Qf) [redacted] These deposits consist of loosely to moderately compacted sand, silt, and gravel deposited in alluvial fans during the Pliocene and Pleistocene ages. The fan deposits likely interfinger with the Flood Basin Deposits. [redacted]

2.7.3.4 [redacted]

The [redacted]

2.7.3.5 [redacted]

The [redacted]

[redacted]

[redacted]

Figure 2.7-3 Estimated [redacted] Thickness and Extent

2.7.3.6 Undifferentiated Non-marine Sediments

The upper Paleogene and Neogene sequence begin with the [redacted] which represents fluvial deposits that blanket the entire southern [redacted]. The unconformity at the base of the [redacted] marks a widespread Oligocene regression and separates the more deformed Mesozoic and lower Paleogene strata below from the less deformed uppermost Paleogene and Neogene strata above. These undifferentiated non-marine sediments contain approximately 3,000 - 10,000 milligrams per liter (mg/l) total dissolved solids (TDS) water and is the lowermost USDW in the AoR (**Figure 2.2-4**).

2.7.4 Geologic Cross Sections Illustrating Formations with USDWs

[redacted]. The geologic sections were originally prepared for [redacted] Lithologic information from well logs was normalized and digitized to generally conform with the Unified Soil Classification System. Lithology and well screens from groundwater monitoring wells constructed since the sections were created were also added to the geologic sections. The soil profiles show the subsurface relationships and location of the formations and coarse-grained sediments that comprise the principal aquifers. [redacted]

Geologic Cross Section B-B' (**Figure 2.7-4)** runs [redacted]

[redacted]

Figure 2.7-4 Geologic Cross Section B-B'

Geologic Cross Section C-C' (**Figure 2.7-5**) runs a northeast-southwest orientation across [redacted] This geologic section illustrates the types of sediments, the estimated base of freshwater, the possible location of the [redacted] (or its equivalent). Where the clay location is uncertain, no wells were present that penetrated deep enough to confirm its presence or absence. The base of fresh water varies throughout the Subbasin and is shown on the sections. It is as shallow as -400 feet msl to as much as -2,000 feet msl (GEI 2021).

[redacted]

Figure 2.7-5 Geologic Cross Section C-C'

2.7.5 Principal Aquifers

[redacted]

2.7.5.1 Upper Aquifer

The Upper Aquifer is used by domestic, community water systems, and for agriculture. The Upper aquifer also supports native vegetation where groundwater levels are less than 30 feet bgs (GEI 2021).

The Upper Aquifer is an unconfined to semi-confined aquifer. It is present above the [redacted]

There are multiple coarse-grained sediment layers that make up the unconfined aquifer, however the water levels are generally similar. Generally, the aquifer confinement tends increase with depth becoming semi-confined conditions. There is also typically a downward gradient in the aquifers (Hotchkiss and Balding 1971) in the non-Delta areas; the gradient ranges from a few feet bgs to as much as 70 feet bgs. [redacted]

The hydraulic characteristics of the unconfined aquifer are highly variable. The USGS estimated horizontal hydraulic conductivity values for organic sediments ranging from 0.0098 ft/d to 133.86 ft/d (Hydrofocus 2015). Wells in the unconfined aquifer produce 6 to 5,300 gpm. [redacted] The storativity is about 0.05 (GEI 2021).

Water quality in the Upper Aquifer is mostly transitional, with no single predominate anion. Most water are characterized as sulfate bicarbonate and chloride bicarbonate type (Hotchkiss and Balding 1971). The TDS of these transitional water ranges between 400 to 4,200 mg/L. Nitrate is generally high in the Upper aquifer in the non-Delta portions of the Subbasin. Nitrate is generally low in the Delta portions of the Subbasin (GEI 2021).

2.7.5.2 Lower Aquifer

[redacted] The Lower Aquifer is mainly comprised of the lower portions of the [redacted] below the [redacted] and extends to the base of fresh water. [redacted] the clay's extent to the west and north is uncertain and has been estimated to have a vertical permeability ranging from 0.01 to 0.007 feet per day (Burow et al. 2004).

The groundwater levels are generally deeper than water levels in the Upper Aquifer (Hotchkiss and Balding 1971). Groundwater levels in the confined aquifer are about -25 to -75 feet msl. The groundwater levels are normally 60 to 200 feet above the top of the [redacted]

Wells in the Lower Aquifer produce about 700 to 2,500 gpm. The transmissivity typically ranges from 12,000 to 37,000 gpd/ft, but can be 120,000 gpd/ft. The storage coefficient or storativity has been measured to be 0.0001 (Padre 2004).

Water quality in the Lower Aquifer in the western portions are chloride type water but mostly transitional type of sulfate chloride near the valley margins and sulfate bicarbonate and bicarbonate sulfate near the [redacted] (Hotchkiss and Balding 1971). In general, the TDS ranges between 400 and 1,600 mg/L. Nitrate is typically low in the Lower Aquifer. [redacted]

2.7.6 Potentiometric Maps

[redacted] To evaluate groundwater levels, the GSP only used wells with known total depths and construction details so that the wells were assigned to a principal aquifer. To supplement data from these wells, additional monitoring wells were located that were being used for other regulatory programs.

2.7.6.1 Upper Aquifer

[redacted]

[redacted]

Figure 2.7-6 Principal Aquifer Schematic Profile

[redacted]

[redacted]

Figure 2.7-7 Upper Aquifer Groundwater Elevations Fall 2019

2.7.6.2 Lower Aquifer

[redacted] Groundwater contours for the Lower Aquifer were developed using data from the CASGEM monitoring wells that [redacted]

[redacted]

Figure 2.7-8 Lower Aquifer Groundwater Elevations Spring 2019

[redacted]

The groundwater gradient in Fall 2019 [redacted] Due to the pumping depression, the gradient increases around the [redacted] The gradient near the western edge

[redacted]

2.7.7 Water Supply and Groundwater Monitoring Wells

The California State Water Resources Control Board Groundwater Ambient Monitoring Assessment Program (GAMA), the Department of Water Resources (DWR), CASGEM, and other public databases were searched to identify any water supply and groundwater monitoring wells within a one-mile radius of the AOR. There are no wells with the AoR. Seven water supply wells were identified within one mile of the AoR. Data provided from public databases indicate that the wells identified are completed much shallower than the proposed injection zone. A map of well locations and table of information are found in **Figure 2.7-9** Water Well Map and **Table 2.7-1** Water Well Information, respectively.

[redacted]

Figure 2.7-9 Water Well Location Map

Groundwater in the Subbasin is used for municipal, industrial, irrigation, domestic, stock watering, frost protection, and other purposes. The number of water wells is based on well logs filed and contained within public records may not reflect the actual number of active wells because many of the wells contained in files may have been destroyed and others may not have been recorded.

[redacted]

2.8 Geochemistry [40 CFR 146.82(a)(6)]

2.8.1 Formation Geochemistry

2.8.1.1 [redacted]

As noted in the mineralogy section (section 2.4.1).

2.8.1.2 Upper Confining Zone [redacted]

As noted in the mineralogy section (section 2.4.1).

2.8.1.3 [redacted]

As noted in the mineralogy section (section 2.4.1).

2.8.2 Fluid Geochemistry

[redacted]. The well [redacted] was sampled for water in 2015. The measurement of total dissolved solids (TDS) for the sample is 15595 mg/L. The complete water chemistry is shown in **Figure 2.8-1**.

[redacted]

Figure 2.8-1: Water geochemistry for the [redacted]

[redacted]

[redacted]

Figure 2.8-2: Gas chromatography for the [redacted]

The location of the [redacted] is shown in Figure 2.8-3.

[redacted]

Figure 2.8-3: Location of wells with geochemistry data.

2.8.3 Fluid-Rock Reactions

2.8.3.1 [redacted]

[redacted]

2.8.3.2 Upper Confining Zone [redacted]

There is no fluid geochemistry analysis for the upper confining zone. The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock and the low carbonate content, the upper confining zone is not expected to be impacted by the CO_2 injectate.

2.8.3.2 [redacted]

There is no fluid geochemistry analysis for the [redacted] The shale will only provide fluid for analysis if stimulated. However, given the low permeability of the rock and the low carbonate content, the [redacted] is not expected to be impacted by the CO_2 injectate.

2.9 Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)

No additional information necessary.

2.10 Site Suitability [40 CFR 146.83]

[redacted]

[redacted]

Thickness maps and petrophysics demonstrate confinement based on the upper confining intervals laterally continuity, low-permeability, and thickness. [redacted]

[redacted]

[redacted]

Figure 2.10-1. Figure showing proximity of CO_2 to the [redacted] and lateral dispersion of CO_2 throughout time and confinement under the overlying [redacted] through time.

CTV estimates maximum storage for the proposed project is [redacted] MMT of CO_2. This was derived from computational modeling.

3.0 AoR and Corrective Action

CTV's AoR and Corrective Action plan pursuant to 40 CFR 146.82(a)(4), 40 CFR 146.82(a)(13) and 146.84(b), and 40 CFR 146.84(c) describes the process, software, and results to establish the AoR, and the wells that require corrective action.

AoR and Corrective Action GSDT Submissions
GSDT Module: AoR and Corrective Action ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☒ Tabulation of all wells within AoR that penetrate confining zone ***[40 CFR 146.82(a)(4)]*** ☒ AoR and Corrective Action Plan ***[40 CFR 146.82(a)(13) and 146.84(b)]*** ☒ Computational modeling details ***[40 CFR 146.84(c)]***

4.0 Financial Responsibility

CTV's Financial Responsibility demonstration pursuant to 140 CFR 146.82(a)(14) and 40 CFR 146.85 is met with a line of credit for Injection Well Plugging and Post-Injection Site Care and Site Closure and insurance to cover Emergency and Remedial Responses.

Financial Responsibility GSDT Submissions
GSDT Module: Financial Responsibility Demonstration ***Tab(s):*** Cost Estimate tab and all applicable financial instrument tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Demonstration of financial responsibility ***[40 CFR 146.82(a)(14) and 146.85]***

5.0 Injection and Monitoring Well Construction

CTV requires seven wells for injection and monitoring associated with CTV II including two injectors, three injection zone monitoring wells, one above zone monitoring well, and one USDW monitoring well. [redacted]

[redacted]

Figure 5.1: Map showing the location of injection wells and monitoring wells.

All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO_2 composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure non-endangerment of USDW. Due to the depth of the base of USDW, an intermediate casing string will be utilized to isolate the USDW. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of USDW using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

[redacted] These conditions are not extreme, and CTV has extensive experience successfully constructing, operating, working over, and plugging wells in depleted reservoirs.

Appendix C-1: Injection and Monitoring Well Schematics provides casing diagram figures for all injection and monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

5.1 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

There are no proposed stimulation programs currently.

5.2 Well Construction Procedures [40 CFR 146.82(a)(12)]

New well construction will occur during pre-operational testing, and no abnormal drilling and completion challenges are anticipated. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO_2 injection rates, to prevent migration of fluids out of the injection zone, to protect the shallow formations, and to allow for monitoring, as described by the following:

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow USDW-bearing zones from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus. This is described in further detail in Attachment G: Construction Details.
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted.
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices.
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO_2 injectate and will limit corrosion.

- Wellhead – stainless steel or other corrosion resistant alloy
- Casing – 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement – portland cement has been used extensively in enhanced oil recovery (EOR) injectors. Data acquired from existing wells supports that the materials are compatible with CO_2 where good cement bond between formation and casing exists.
- Tubing – 13Cr L-80 or other corrosion resistant alloy
- Packer – corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 – Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 – Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 – Downhole Equipment – Packers and Bridge Plugs

As required by §146.86(b)(1), the existing and proposed casing and proposed tubing properties (sizes, thicknesses, and grades) have been evaluated to ensure the well can withstand the combinations of internal pressures, external pressures, and axial loads that the well will encounter throughout the construction, conversion, operation and plugging phases of the project. Load cases identified using oil and gas industry best practices as well as specific CO_2 injection loads were modeled using industry-accepted casing design software, StrinGnosis. Load scenarios were calculated for the intermediate casing, the injection casing/liner, and the tubing string with the assumption of 87.5% remaining body wall thickness (manufacturer's tolerance for new pipe). Load types assessed in the load scenarios include burst, collapse, axial (tensile and compressive), and triaxial (Von Mises Equivalent). Temperature effects under static or dynamic conditions, based on load scenario, have been incorporated into the modelling results. The design results indicate the materials currently installed have strengths sufficient to withstand all worst-case load scenarios and include industry-standard safety factors.

5.2.1 Casing and Cementing

The casing specification in Appendix C-1: Injection and Monitoring Well Schematics are sufficient to meet the requirements of 40 CFR 146.86(b)(1)(iv) and to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure (MAOP) of 0.63 psi/ft, specified in the Appendix: Operating Procedures and to be confirmed during pre-operational testing.

[redacted] These conditions are not extreme, and CTV has extensive experience successfully constructing wells in depleted reservoirs. Standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement. Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

[redacted]

[redacted]

[redacted]

5.2.2 *Tubing and Packer*

The information in the tables provided in Appendix C-1: Injection and Monitoring Well Schematics is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined prior to completion or conversion during pre-operational testing and will be sufficient to withstand all load scenarios considering internal pressure, external pressure, axial loading, and temperature effects.

5.2.3 Annular Fluid

4% KCl completion fluid treated with corrosion inhibitor and biocide will be circulated in the tubing/casing annulus at the time of tubing installation. The corrosion inhibitor and biocide additives will be compatible with the wellbore environment and bottomhole temperatures to prevent internal corrosion of the casing and external corrosion of the tubing.

5.2.4 Injectate and Formation Fluid Properties

CTV is planning to construct a carbon capture and sequestration "hub" project (*i.e.*, a project that collects carbon dioxide (CO_2) from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC permitted injection well(s)). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. [redacted] The CO_2 stream from the source(s) will consist of a minimum of 95% CO_2 by volume. Incidental substances in associated with the CO_2 stream may include, for example, water content (<25 lb/mmscf), oxygen, H_2S, and SO_x compounds. CTV would expect the CO_2 stream will be sampled at the transfer point from the source and analyzed according to the analytical methods described in the "CTV II – QASP" (Table 4) document and the "Att C – CTV II Testing & Monitoring plan" (Table 1) document. Should the injectate not meet the minimum requirements, it will be rejected.

The anticipated injection temperature at the wellhead is 90 – 130° F.

A 100% CO_2 injectate stream has been assumed for computational modeling and for the well performance modeling. Table 5.1 summarizes the injectate properties at downhole conditions for the injectors over the life of the project. The formation fluid properties and composition are covered in detail in Section 2.8.2 of the narrative document.

Table 5.1: Injectate properties at downhole conditions (Assuming 100% CO_2 injectate)

Injectate property at downhole conditions	Injector 1 [redacted]	Injector 2 [redacted]
Viscosity, cp (Start / End)	0.024 / 0.075	0.024 / 0.074
Density, lb/ft^3 (Start / End)	15.71 / 51.85	15.09 / 51.59
Compressibility factor, Z (Start / End)	0.640 / 0.613	0.646 / 0.610
Injection rate, mmscfpd (Average)	[redacted]	[redacted]

No corrosion is expected in the absence of free phase water provided that the entrained water is kept in solution with the CO_2. This is ensured by the <25 lb/mmscf injectate specification limit, and this specification will be a condition of custody transfer at the capture facility. For transport through pipelines, which typically use standard alloy pipeline materials, this specification is critical to the mechanical integrity of the pipeline network, and out of specification product will be immediately rejected. Therefore, all product transported through pipeline to the injection wellhead is expected to be dry phase CO_2 with no free phase water present.

Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate any potential corrosion impact should free-phase water from the reservoir become present in the wellbore, such as during shut-in events when formation liquids, if present, could backflow into the wellbore. CTV may further optimize the maximum water content specification prior to injection based on technical analysis.

Geochemical analysis of the connate formation water has been provided in section 2.8 Geochemistry of the Attachment A narrative document and does not indicate corrosiveness to standard cement and casing materials. A formation water analysis will be obtained during pre-operational testing and reviewed to ensure compatibility with well construction materials. Table 5.2 provides estimated formation fluid properties.

Table 5.2: Formation fluid properties

Formation Fluid Property	Formation Water	Formation Gas
Density, g/cm^3	1.0082	0.00076
Viscosity, cp	1.26	0.029
TDS, ppm	~15,000	NA

5.2.5 Alarms and Shut-Off Devices

As described in the Testing and Monitoring Plan, injection wells will be configured with real-time injection rate, injection pressure, and annular pressure monitoring and alarms. The Operating Procedures plan details the maximum injection rate and pressure thresholds for alarms and shut-off devices.

A surface shut-off valve will be installed on the wellhead and configured with automation and communication to the Central Control Facility (CCF). The valve will be utilized by the CCF operator remotely to respond to an emergency by shutting in the well. The valve will be configured to automatically shut-in the well if tubing or annular alarm thresholds are exceeded.

The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

6.0 Pre-Operational Logging and Testing

CTV has indicated a proposed pre-operational logging and testing plan throughout the application documentation pursuant to 40 CFR 146.82(a)(8). Attachment G: Well Construction Details includes logging and testing plans for newly drilled wells based on requirements defined within 40 CFR 146.87.

Pre-Operational Logging and Testing GSDT Submissions
GSDT Module: Pre-Operational Testing ***Tab(s):*** Welcome tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Proposed pre-operational testing program ***[40 CFR 146.82(a)(8) and 146.87]***

7.0 Well Operation

CTV has provided detailed operating procedures for each injection well. These procedures are provided for both injectors in the Appendix: Operating Procedures document. Example of operational procedure for planned injector conversion of [redacted] is included below.

7.1 Operational Procedures [40 CFR 146.82(a)(10)]

For an Average (/ Target) rate of [redacted] million standard cubic feet per day (mmscf/d), bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the reservoir simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO_2 EOR to model CO_2 injection wells. The pressures have been currently calculated assuming a 100% CO_2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, surface and bottom hole injection pressures of 945 psi and 1,533 psi respectively, are required to inject the target rate. As the pressure in the reservoir builds up, increasing surface and bottom hole pressures will be required to maintain injection at the target rate. At the end of injection, the estimated surface and bottom hole pressures required are 1,425 psi and 4,711 psi, respectively.

The expected fracture pressure gradient for the injection zone is estimated to be 0.7 – 0.8 psi/ft, and 0.70 psi/ft is conservatively used for the wellbore performance modelling. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 6,021 psi (calculated at the top perforation). Reservoir fracture gradient will be determined with step-rate testing during pre-operational testing to confirm maximum allowable injection pressure. During injection, the well will be controlled using automation to never exceed the maximum allowable bottomhole injection pressure. The estimated bottom hole pressures over the life of the project are lower than the maximum allowable bottom hole pressure of 6,021 psi.

The expected beginning and ending pressures for injector [redacted] are summarized in Table 7.1.

Table 7-1: Proposed operational conditions

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.70 psi/ft frac gradient with 10% safety factor	
Surface	2,529	psig
Downhole	6,021	psig
Average (/ Target) Injection Rate	[redacted]	mmscf/d
Injection Pressure @ Average Rate	Expected range over project	
Surface – Start / End / Average	945 / 1,425 / 1,185	psig
Downhole – Start / End / Average	1,533 / 4,711 / 3,122	psig
Maximum Proposed Injection Rate	[redacted]	mmscf/d
Injection Pressure @ Maximum Proposed Rate	Expected range over project	
Surface – Start / End / Average	1,030 / 1,585 / 1,308	psig
Downhole – Start / End / Average	1,681 / 4,819 / 3,250	psig
Average Injection Volume and/or Mass	[redacted] million	tons
Annulus Pressure @ Target Rate	Expected range over project	
Surface – Start / End	100 / 632	psig
Downhole – Start / End	4,279 / 4,811	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

7.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

CTV is planning to construct a carbon capture and sequestration "hub" project (*i.e.*, a project that collects carbon dioxide (CO_2) from multiple sources over time and injects the CO_2 stream(s) via a Class VI UIC permitted injection well(s)). Therefore, CTV is currently considering multiple sources of anthropogenic CO_2 for the project. [redacted] The CO_2 stream from the source(s) will consist of a minimum of 95% CO_2 by volume. Incidental substances in associated with the CO_2 stream may include, for example, water content (<25 lb/mmscf), oxygen, H_2S, and SO_x compounds. CTV would expect the CO_2 stream will be sampled at the transfer point from the source and analyzed according to the analytical methods described in the "CTV II – QASP" (Table 4) document and the "Att C – CTV II Testing & Monitoring plan" (Table 1) document. Should the injectate not meet the minimum requirements, it will be rejected.

The anticipated injection temperature at the wellhead is 90 – 130° F.

No corrosion is expected in the absence of free phase water provided that the entrained water is kept in solution with the CO_2. This is ensured by the <25 lb/mmscf injectate specification limit, and this specification will be a condition of custody transfer at the capture facility. For transport through pipelines, which typically use standard alloy pipeline materials, this specification is critical to the mechanical integrity of the pipeline network, and out of specification product will be immediately rejected. Therefore, all product transported through pipeline to the injection wellhead is expected to be dry phase CO_2 with no free phase water present.

Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate any potential corrosion impact should free-phase water from the reservoir become present in the wellbore, such as during shut-in events when formation liquids, if present, could backflow into the wellbore. CTV may further optimize the maximum water content specification prior to injection based on technical analysis.

8.0 Testing and Monitoring

CTV's Testing and Monitoring plan pursuant to 40 CFR 146.82 (a) (15) and 40 CFR 146.90 describes the strategies for testing and monitoring to ensure protection of the USDW, injection well mechanical integrity, and plume monitoring.

Testing and Monitoring GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Testing and Monitoring tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Testing and Monitoring Plan ***[40 CFR 146.82(a)(15) and 146.90]***

9.0 Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Injection Well Plugging GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Injection Well Plugging tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Injection Well Plugging Plan ***[40 CFR 146.82(a)(16) and 146.92(b)]***

10.0 Post-Injection Site Care (PISC) and Site Closure

CTV has developed a Post-Injection Site Care and Site Closure plan pursuant to 40 CFR 146.93 (a) to define post-injection testing and monitoring.

At this time CTV is not proposing an alternative PISC timeframe.

PISC and Site Closure GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** PISC and Site Closure tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ PISC and Site Closure Plan ***[40 CFR 146.82(a)(17) and 146.93(a)]***
GSDT Module: Alternative PISC Timeframe Demonstration ***Tab(s):*** All tabs (only if an alternative PISC timeframe is requested) Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Alternative PISC timeframe demonstration ***[40 CFR 146.82(a)(18) and 146.93(c)]***

11.0 Emergency and Remedial Response

CTV's Emergency and Remedial Response plan pursuant to 40 CFR 164.94 describes the process and response to emergencies to ensure USDW protection.

Emergency and Remedial Response GSDT Submissions
GSDT Module: Project Plan Submissions ***Tab(s):*** Emergency and Remedial Response tab Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Emergency and Remedial Response Plan ***[40 CFR 146.82(a)(19) and 146.94(a)]***

12.0 Injection Depth Waiver and Aquifer Exemption Expansion

No depth waiver or Aquifer Exemption expansion is being requested as part of this application.

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
GSDT Module: Injection Depth Waivers and Aquifer Exemption Expansions ***Tab(s):*** All applicable tabs Please use the checkbox(es) to verify the following information was submitted to the GSDT: ☐ Injection Depth Waiver supplemental report ***[40 CFR 146.82(d) and 146.95(a)]*** ☐ Aquifer exemption expansion request and data ***[40 CFR 146.4(d) and 144.7(d)]***

13.0 References

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NARRATIVE REPORT - FIGURES

[redacted]

Figure 2.1-1. Location map of the [redacted] (red) in relation to the Sacramento Basin.

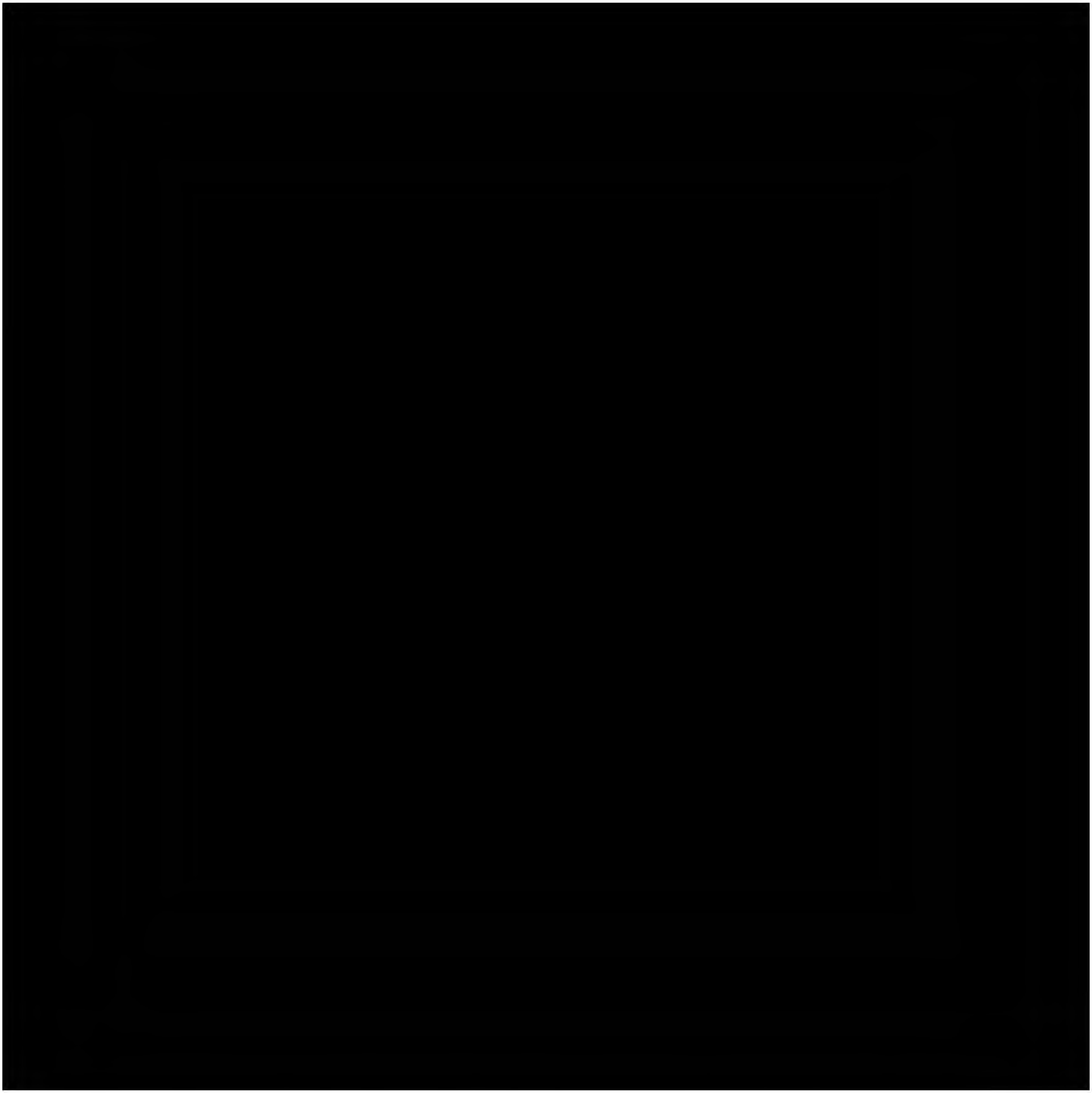

Figure 2.1-2. Location map of California modified from (Beyer, 1988) & (Sullivan, 2012). The Sacramento Basin regional study area is outlined by a dashed black line. B – Bakersfield; F – Fresno; R – Redding.

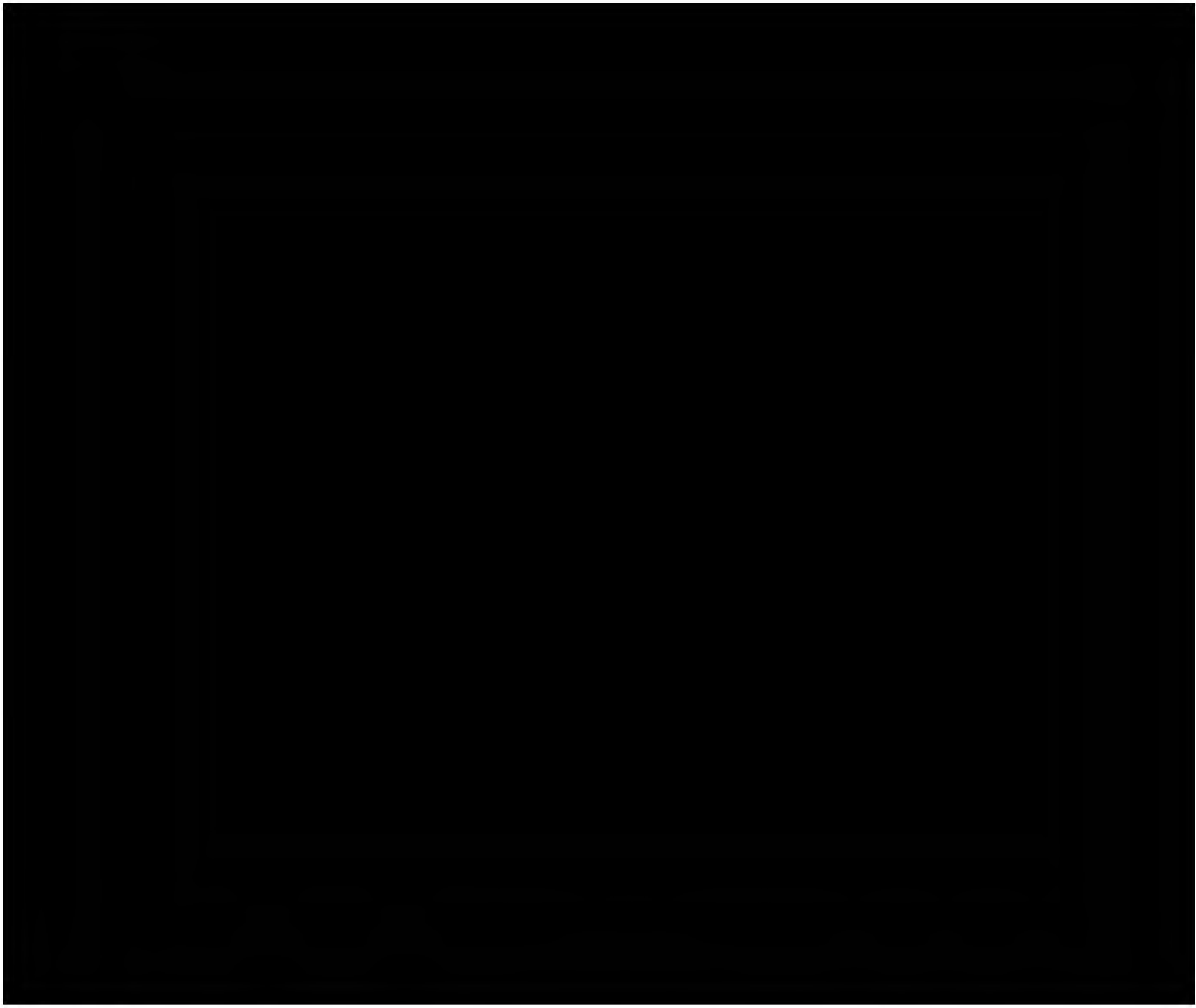

Figure 2.1-3. Migrational position of the Mendocino triple junction (Connection point of the Gorda, North American and Pacific plates) on the west and migrational position of Sierran arc volcanism in the east (Graham, 1984). Figure indicates space-time relations of major continental-margin tectonic events in California during Miocene.

Figure 2.1-4. Schematic W-E cross-section of California, highlighting the Sacramento Basin, as a continental margin during late Mesozoic. The oceanic Farallon plate was forced below the west coast of the North American continental plate.

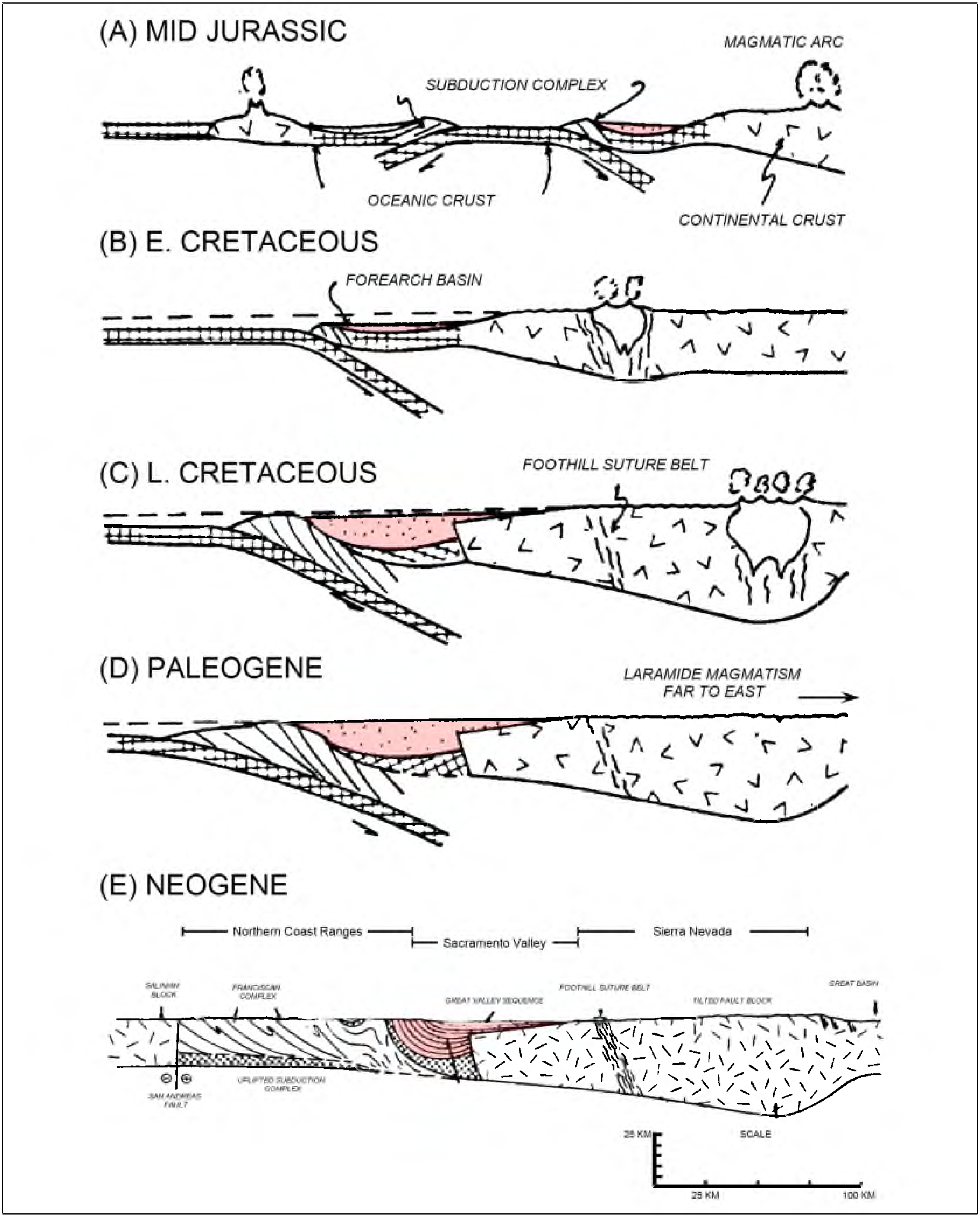

Figure 2.1-5. Evolutionary stages showing the history of the arc-trench system of California from Jurassic (A) to Neogene (E) (modified from Beyer, 1988).

[redacted]

Figure 2.1-6. Schematic northwest to southeast cross section in the Sacramento basin.

[redacted]

FIGURE 2.1-7. [redacted] isopach map for the greater storage project area. Wells shown as blue dots on the map penetrate the [redacted] and have open-hole logs. Wells with relative permeability or capillary pressure data are shown as magenta circles.

[redacted]

Figure 2.2-1. Wells drilled in the [redacted] with porosity data are shown in black, wells with core are shown in green and wells used for ductility calculation are shown in pink.

[redacted]

Figure 2.2-2. Type well taken from south of the AoR showing average rock properties used in the model for confining and injection zones.

[redacted]

Figure 2.2-3. Summary map and area of seismic data used to build structural model. Both of the 3D surveys were acquired in 1998 and reprocessed in 2013. The 2D seismic were acquired between 1980 and 1985. California gas fields are shown for reference.

[redacted]

Figure 2.2-4. Cross section showing stratigraphy and lateral continuity of major formations across the project area.

[redacted]

Figure 2.2-5. (a) [redacted] reservoir thickness map. (b) [redacted] reservoir structure map.

[redacted]

Figure 2.2-6. Injection well location map for the project area. Injection wells are 1,735 ft. apart.

[redacted]

Figure 2.2-7 Surface Features and the AoR

[redacted]

Figure 2.2-8 State and EPA approved Cleanup Sites

[redacted]

Figure 2.3-1. [redacted] Yellow line highlights the cross-section shown in **Figure 2.3-2**.

[redacted]

Figure 2.3-2. Structural cross section across the geologic model. Well [redacted] is shown with SP log (negative values to left) for correlation and geologic packages. Geologic surfaces developed from seismic interpretation. [redacted]

[redacted]

Figure 2.4-1. Map showing location of wells with mineralogy data relative to the AoR.

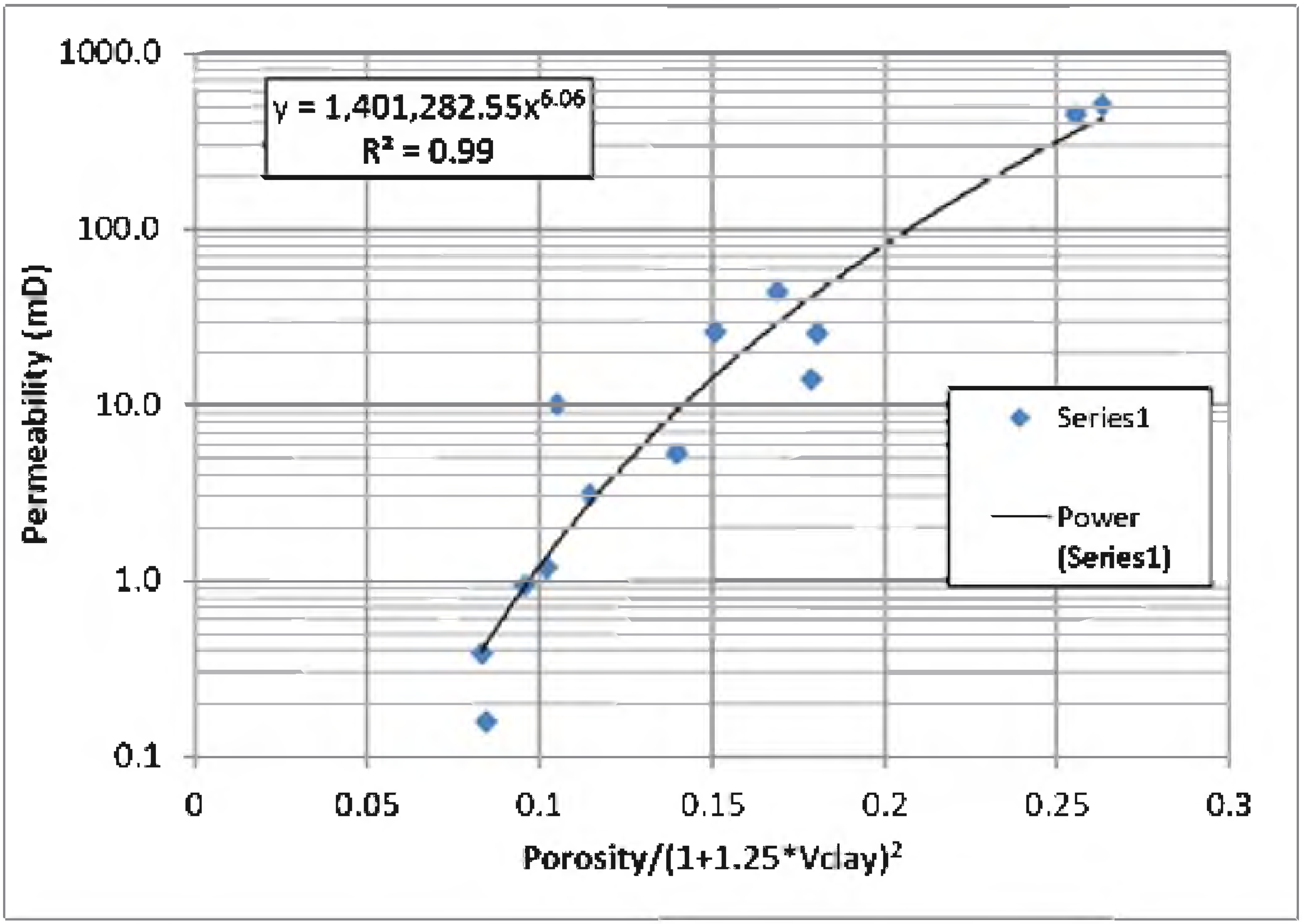

Figure 2.4-2. Permeability transform for Sacramento basin zones.

[redacted]

Figure 2.4-3. Porosity histogram for well [redacted] In the histogram, blue represents the [redacted] red the [redacted] and brown the [redacted] For the two shale intervals, only data with VCL>0.25 is shown, and for the [redacted] only data with VCL<=0.25 is shown.

[redacted]

Figure 2.4-4. Permeability histogram for well [redacted] In the histogram, blue represents the [redacted] red the [redacted] and brown the [redacted] For the two shale intervals, only data with VCL>0.25 is shown, and for the [redacted] only data with VCL<=0.25 is shown.

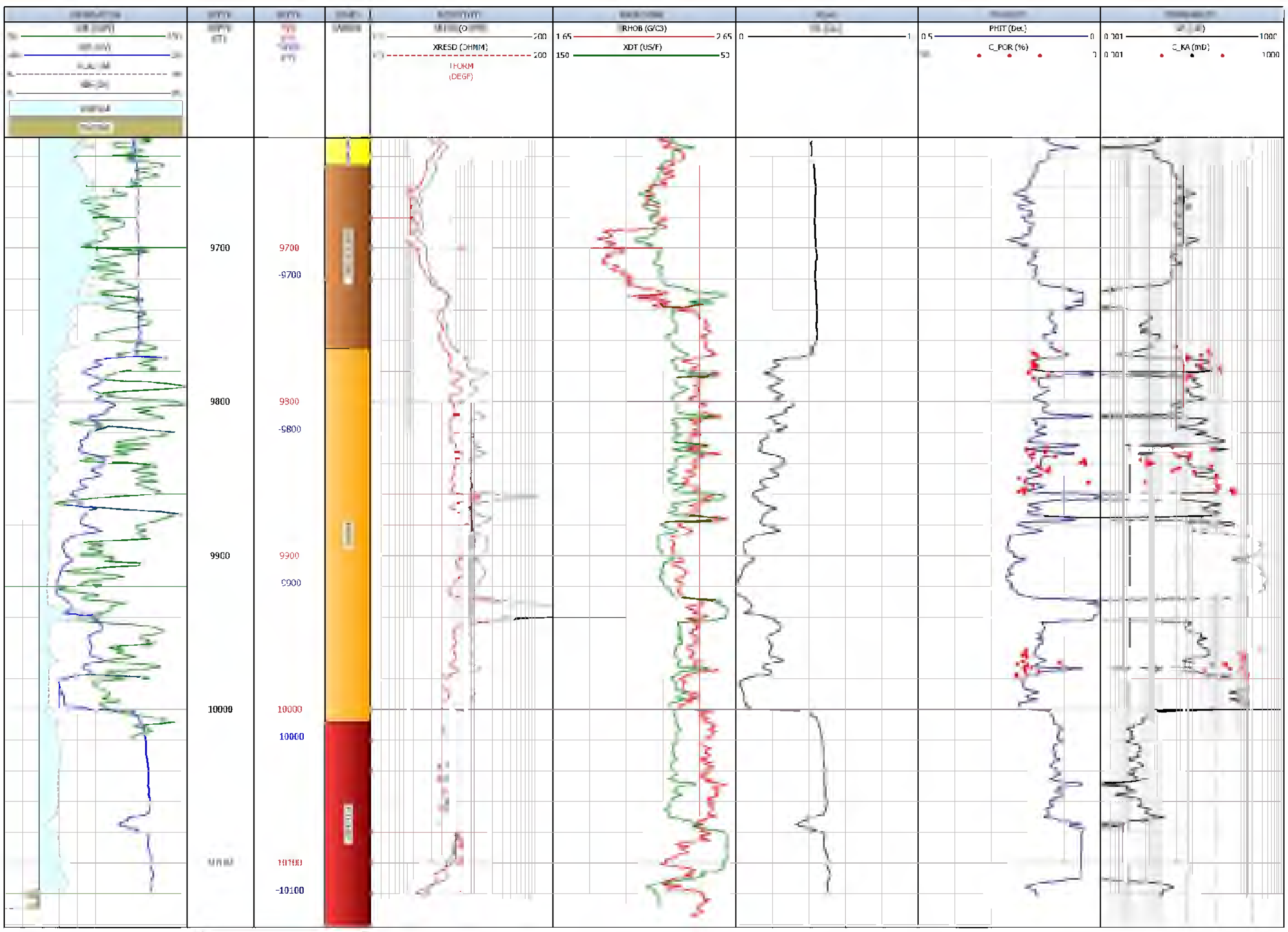

Figure 2.4-5. Log plot for well [redacted], showing the log curves used as inputs into calculations of clay volume, porosity and permeability, and their outputs. Core data for porosity and permeability is shown for comparison to the log model. Track 1: Correlation and caliper logs. Track 2: Measured depth. Track 3: Vertical depth and vertical subsea depth. Track 4: Zones. Track 5: Resistivity. Track 6: Compressional sonic and density logs. Track 7: Volume of clay. Track 8: Porosity calculated from log curves and core porosity. Track 9: Permeability calculated using transform and core permeability.

[redacted]

Figure 2.4-6. Map of wells with porosity and permeability data.

[redacted]

Figure 2.4-7. Thickness and depth maps within the AoR for the [redacted] reservoir and [redacted]

[redacted]

Figure 2.4-8. Thickness and structure maps for the [redacted] and [redacted] within the AoR.

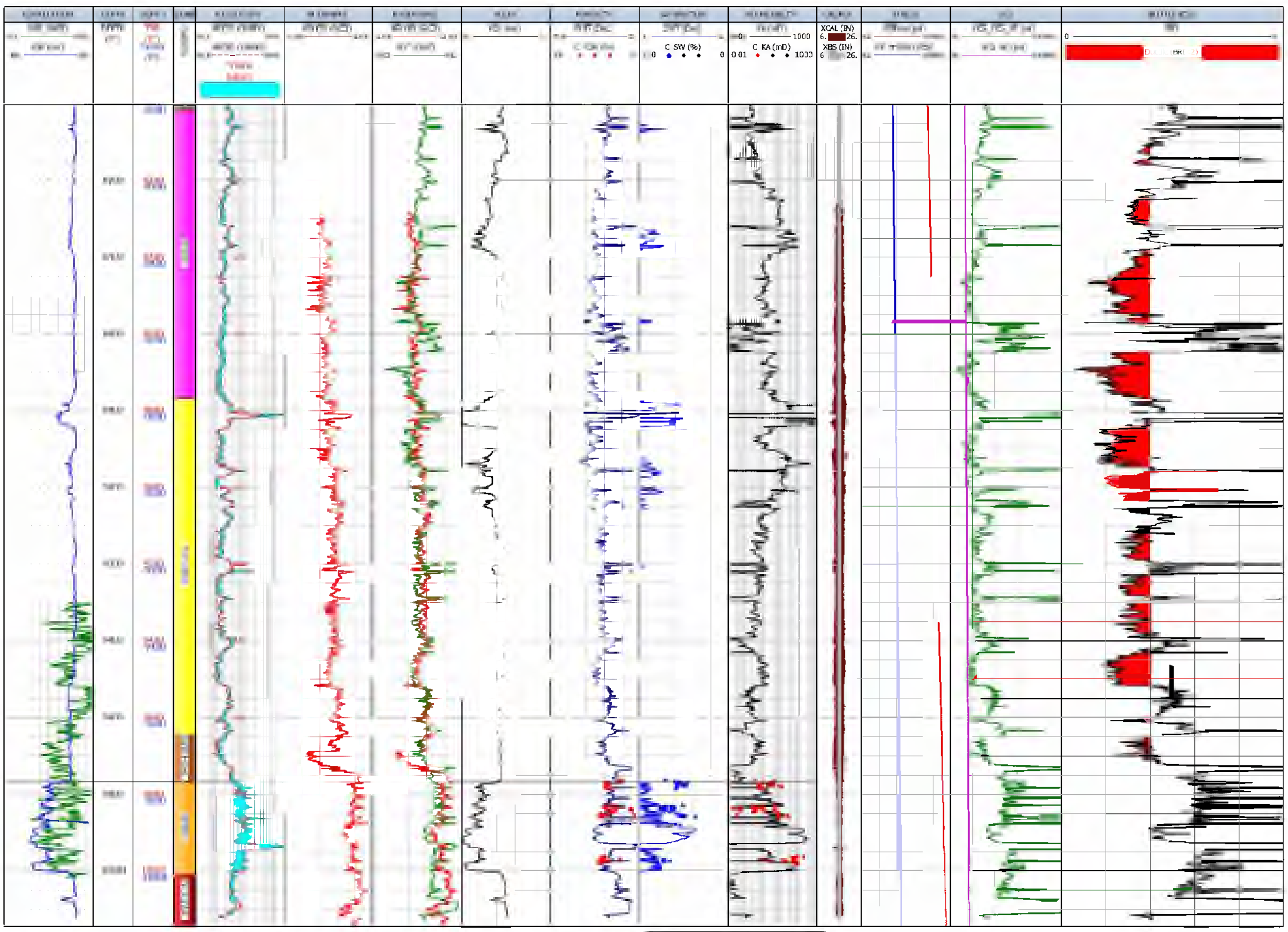

Figure 2.5-1: Unconfined compressive strength and ductility calculations for well [redacted] The upper confining zone ductility is less than two, as are most of the [redacted] Track 1: Correlation logs. Track 2: Measured depth. Track 3: Vertical depth and vertical subsea depth. Track 4: Zones. Track 5: Resistivity. Track 6: Density log. Track 7: Density and compressional sonic logs. Track 8: Volume of clay. Track 9: Porosity calculated from sonic and density. Track 10: Water saturation. Track 11: Permeability. Track 12: Caliper. Track 13: Overburden pressure and hydrostatic pore pressure. Track 14: UCS and UCS_NC. Track 15: Brittleness.

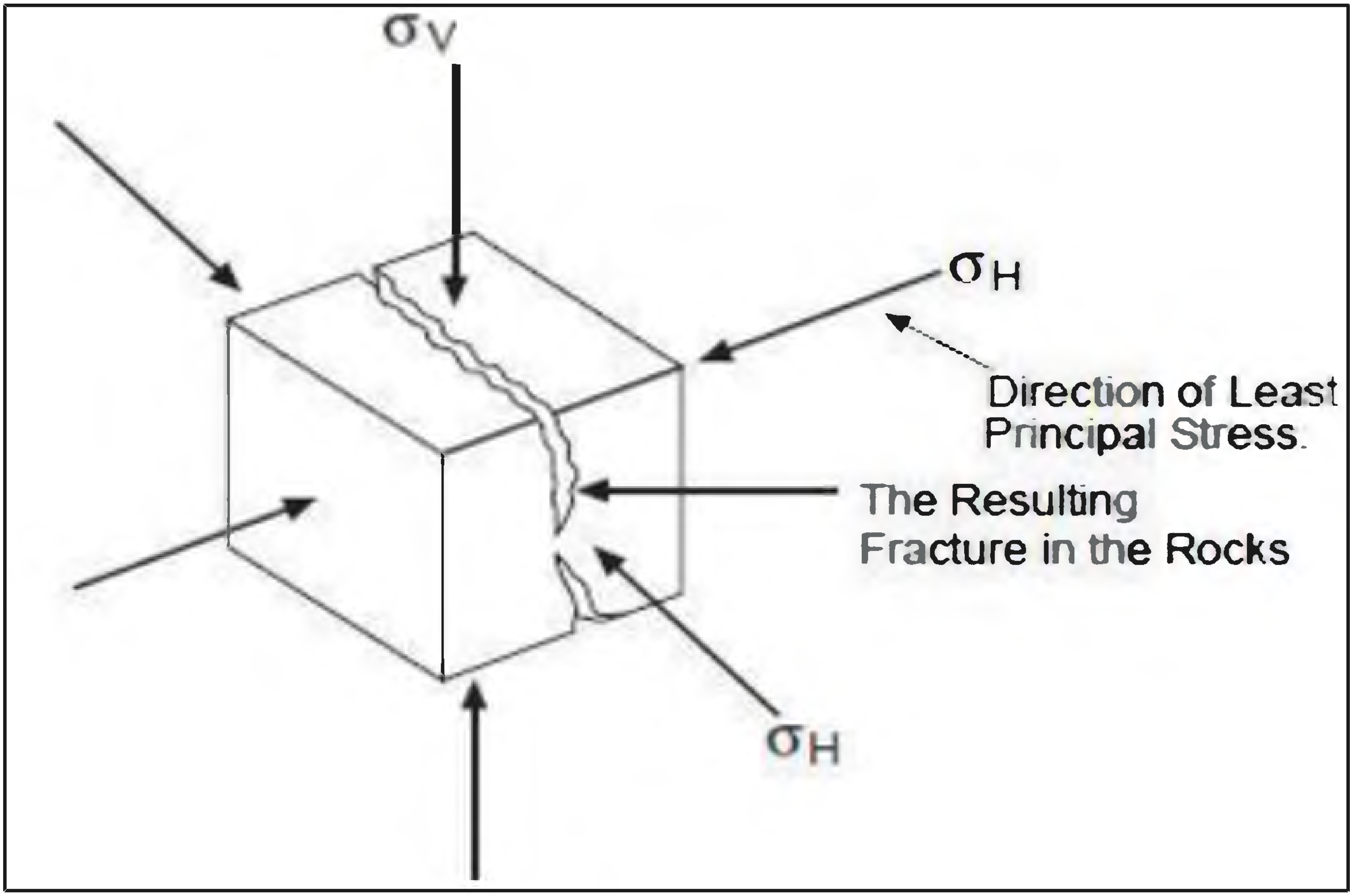

Figure 2.5-2: Stress diagram showing the three principal stresses and the fracturing that will occur perpendicular to the minimum principal stress.

[redacted]

Figure 2.5-3: World Stress Map output showing S_{Hmax} azimuth indicators and earthquake faulting styles in the [redacted] (Heidbach et al., 2016). In red is the outline of the [redacted] The background coloring represents topography.

[redacted]

Figure 2.5-4: Location of wells with FIT data.

[redacted]

Figure 2.6-1. Fault Activity Map from the California Geologic Survey. [redacted] The fault trace is not colored indicating it is interpreted as Pre-Quaternary (older than 1.6 million years) by the California Geologic Survey. This is also in agreement with the seismic and well-based interpretation. (https://maps.conservation.ca.gov/cgs/fam/).

Figure 2.6-2. Image is modified from USGS search results. Data from these events are compiled in **Table 2.6-1** in chronological order associated with events 1 through 11 on the map.

[redacted]

Figure 2.6-3. Image modified from Lund Snee and Zoback (2020) showing relative stress magnitudes across California. Red star indicates CTV II site area.

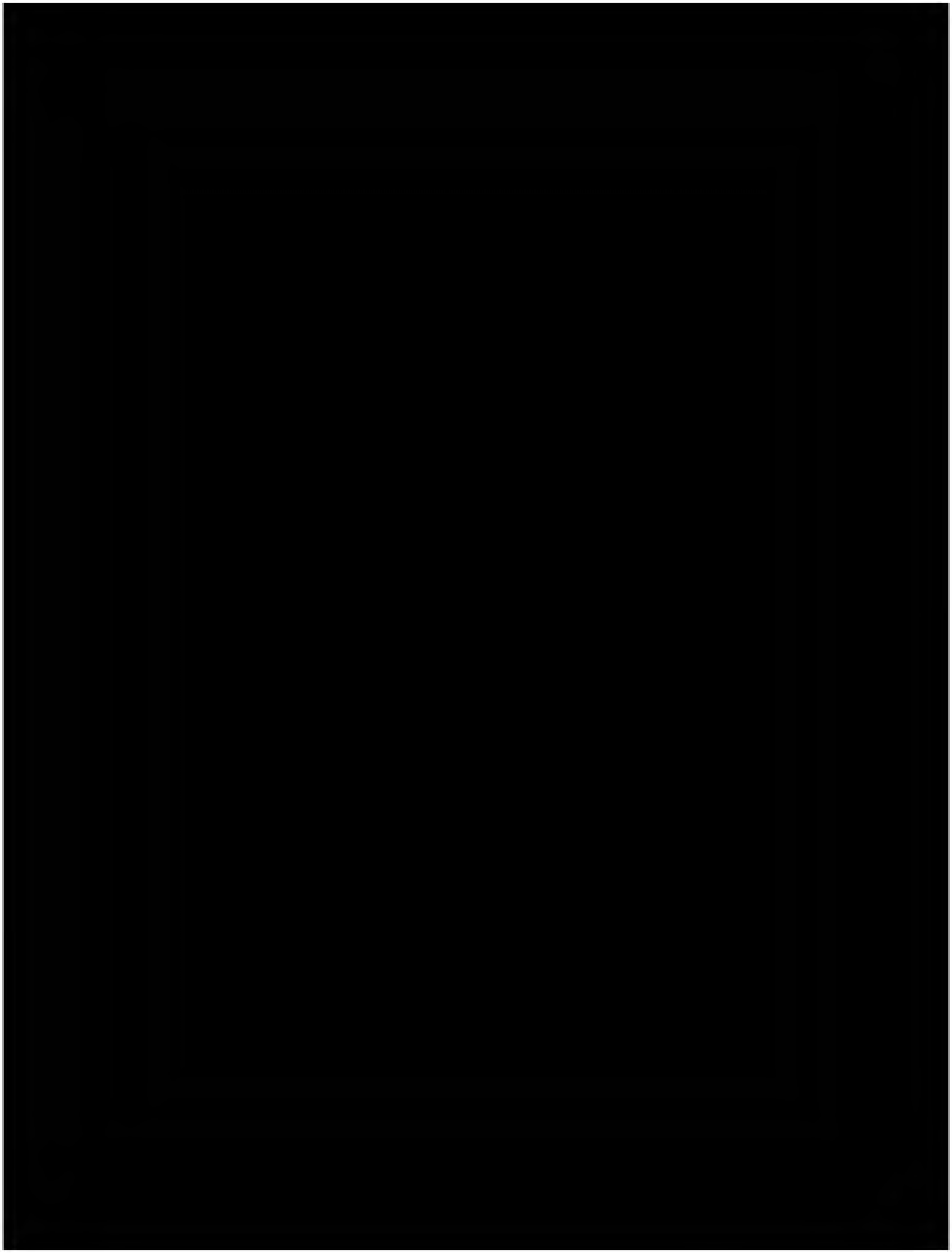

Figure 2.7-1 Tracy Subbasin, Surface Geology, and Cross Section Index Map

[redacted]

Figure 2.7-2 Geologic Map and Base of Fresh Water

[redacted]

Figure 2.7-3 Estimated [redacted] Thickness and Extent

[redacted]

Figure 2.7-4 Geologic Cross Section B-B'

[redacted]

Figure 2.7-5 Geologic Cross Section C- C'

[redacted]

Figure 2.7-6 Principal Aquifer Schematic Profile

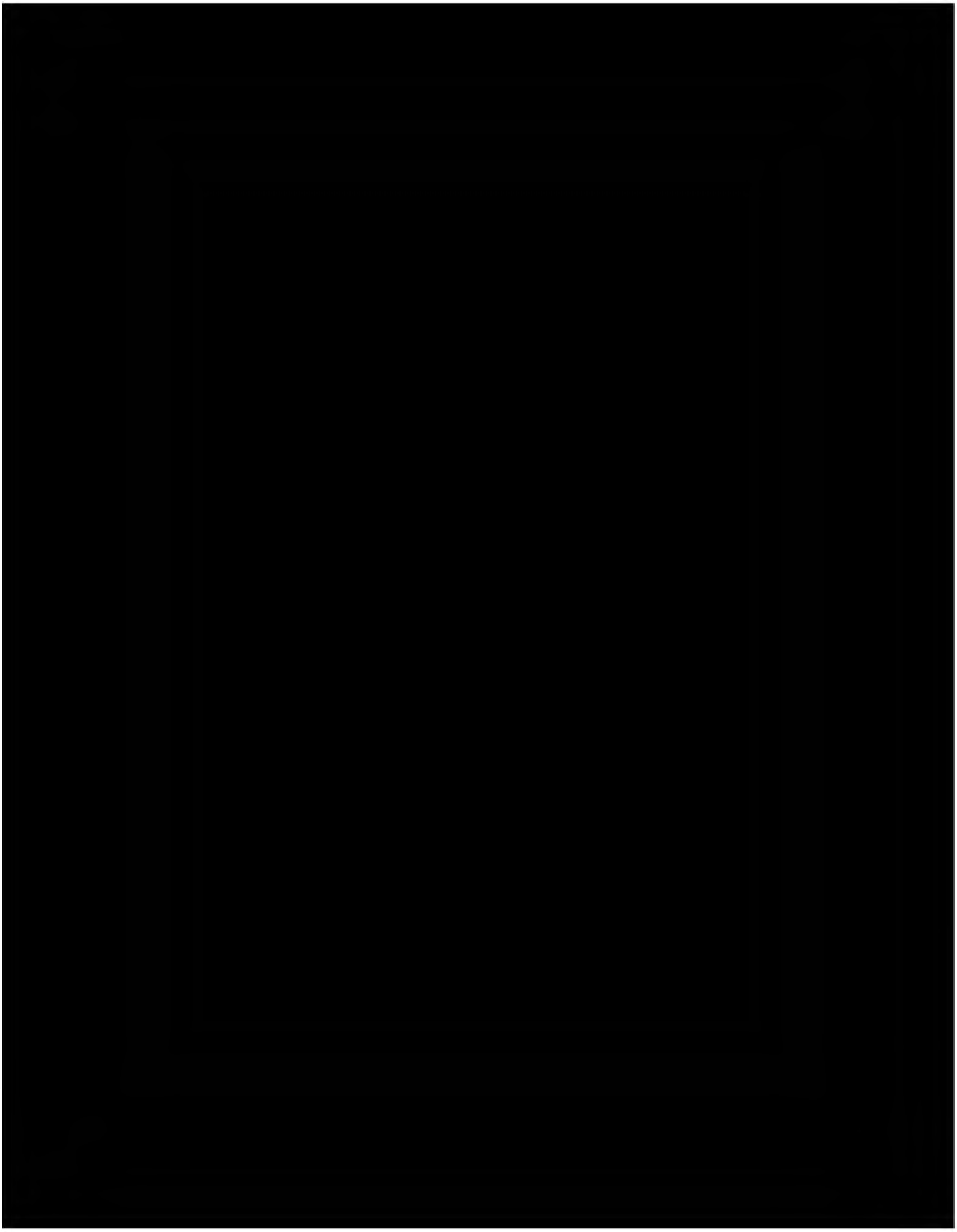

Figure 2.7-7 Upper Aquifer Groundwater Elevation- Fall 2019

[redacted]

Figure 2.7-8 Lower Aquifer Groundwater Elevation- Spring 2019

[redacted]

Figure 2.7-9 Water Well Location Map

[redacted]

Figure 2.8-1: Water geochemistry for the [redacted].

[redacted]

Figure 2.8-2: [redacted]

[redacted]

Figure 2.8-3: Location of wells with geochemistry data.

NARRATIVE REPORT - TABLES

Table 2.4-1: Formation mineralogy from X-ray diffraction in [redacted] and XRD and Fourier transform infrared spectroscopy (FTIR) in the [redacted]

[redacted]

Table 2.4-2: [redacted] gross thickness and depth within the AoR.

Zone	Property	Low	High	Mean
Upper Confining Zone [redacted]	Thickness (feet)	2,158	2,322	2,243
	Depth (feet TVD)	7,208	7,788	7,456
Reservoir [redacted]	Thickness (feet)	120	365	256
	Depth (feet TVD)	9,482	9,994	9,727

Table 2.6-1: Data from USGS earthquake catalog for faults in the region of CTV II.

[redacted]

Table 2.7-1- Water Supply Well Information

[redacted]